Bulk System Reliability for Tomorrow's Grid

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Center for Applied Environmental Law and Policy

December 20, 2023

Brattle

Center for Applied Environmental Law and Policy

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Executive Summary

The purpose of this study is to explain the key challenges and opportunities in maintaining a reliable bulk transmission system in the U.S. electric industry experiencing fundamental change.[1] Specifically, we identify: (1) the key trends that are changing the electricity system, and their major drivers; (2) how each trend can support and/or stress various aspects of system reliability; (3) the reforms designed to respond to these reliability effects, and the extent to which the foregoing trends would or would not accelerate the need for such reforms; and (4) in the scenario where reliability reforms are not prioritized to keep pace with industry trends, how compliance flexibilities built into federal environmental regulations (which partly contribute to some industry trends) could help in maintaining reliable system operations nonetheless.[2] We have summarized data, trends, policies, and conclusions from recent studies and reports on the evolving electric industry and reliability needs by regulators, system operators, industry participants, and industry observers, including previous studies by experts from The Brattle Group.

Based on definitions from the North American Electric Reliability Corporation (NERC), the entity empowered with federal authority to coordinate and ensure regional reliability in North America, we focus on four aspects of system reliability:

- **Capacity adequacy**, met when there are sufficient installed resources to meet peak demand
- **Long-term energy adequacy**, met when there are enough installed resources to meet demand in every hour of the year (a planning concept with renewed interest as wind, solar, and battery resources have proliferated)
- **Operational energy adequacy**, met when supply and demand are continuously balanced in real-time even under uncertainty and large fluctuations in supply and demand
- **Operating reliability,** met when the electric grid sustains sudden disturbances and can recover to normal operations quickly

1 We focus on the reliability of the bulk transmission system, setting aside reliability on the local distribution system.

2 Such as U.S. Environmental Protection Agency's Good Neighbor Plan to reduce emissions of NOx in certain states.

We explain how industry changes as well as reform efforts impact these four aspects of reliability. The key findings in our study are as follows:

1. **The electric grid has been undergoing fundamental changes that will likely continue at an increasing pace in the future**

Over the last two decades, the electric grid has been evolving in multiple respects, including increases in the share of renewable (largely wind and solar plants) and gas-fired generation, coal retirements, and expansion of centralized regional wholesale power markets, all against a background of extraordinarily low growth in electricity demand. These changes have been driven by cost reductions and performance improvements in renewable and gas-fired resources and energy efficiency technologies, state clean energy policies, and federal environmental regulations, among other drivers. At the same time, the impact of extreme weather events has been increasing.

In future years, industry expectations point to continuation and acceleration of some past trends including the increase in renewable generation, further acceleration of storage deployment, continued retirements of coal-fired plants, and expansion of regional power system operations and markets, especially in the West. New trends are also expected to emerge, in particular increased growth in demand for electricity. Electrification of heating and transportation together with new sources of demand such as reshoring, data centers, and other emerging industries could double or triple the demand for electricity over the next few decades. This could result in additional reliability stress, but also could provide an opportunity to integrate large amounts of flexible demand to help balance increasingly variable supply.

2. **Continued reforms to reliability processes and tools will be needed to address evolving reliability challenges**

Grid operators have a suite of tools available to manage each of the four aspects of reliability, even as conditions change. However, there have been challenges in each domain as the power grid evolves in comprehensive ways.

These evolutions pose reliability questions:

- Adding generation capacity (such as from new wind, solar, and gas plants) increases capacity adequacy, while retiring generation (such as from coal plants) decreases it. Considering these resource mix changes, does the system exhibit more or less adequacy on net, especially in light of the distinctive characteristics of the new resources? What reforms to long-term energy adequacy analysis are needed to accurately assess this question?

- With growing demand and the rising impact of extreme weather in recent years, how can we maintain and improve system resilience during this transition so that the grid can sustain and recover from extreme events that fall outside of past weather patterns?
- How can the reliability benefits of gas generation be improved and accurately quantified given increasing vulnerability to extreme cold (and hot) weather (especially important in light of growing dependence on electricity for heat and other basic needs)?
- Are we confident the new resources are providing the necessary reliability attributes in the appropriate quantities to replace the lost contributions of conventional generators that are no longer running or that have retired?
- How can grid operators fully take advantage of low-cost wind and solar output on a daily basis, given that the output can drop off quickly, and that power must be instantaneously replaced in order to achieve operational energy adequacy?
- How can grid operators incentivize flexible resources like gas-fired plants, battery storage, and flexible demand to incur costs (like scheduling gas or saving energy for a later need that could be sold at a profit now) to be available during the potential hours of tight supply conditions, even if it is uncertain whether they will ultimately be needed?
- Is the new inverter-based technology used to run wind and solar power generators, batteries, and modern high-voltage direct current (HVDC) transmission facilities ready and able to maintain stability of the power grid in support of operating reliability? If so, what processes are needed to ensure the right technology is installed? If not, what remedies are available that minimally interfere with the economically optimal resource mix transition?

Grid operators have assessed each of these questions in depth and developed an array of enhancements to existing tools in order to find solutions. These include: improved planning models that account for every hour of the year; increased procurements of operating reserves (and development of new types of reserves); and requirements on new resource types to provide Essential Reliability Services that until recently were only provided by conventional generators.[3]

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[3] The term "Essential Reliability Services" (ERS) refers to the set of system attributes or resource capabilities that facilitate operating reliability together with the set of resource capabilities that facilitate operational energy adequacy. Most Essential Reliability Services are secured on an ongoing basis as "ancillary services", which exhibit varying degrees of standardization across the industry. See Section III and Section IV for more detail.

We find that the need for some reliability reforms (such as more explicit management of operating reliability and certain Essential Reliability Services) is tied to increasing penetration of wind, solar, and batteries, and not directly affected by coal retirements. Meanwhile, others (such as the need for more accurate long-term energy adequacy planning) are directly affected by coal retirements. To the extent that the pace of future coal retirements is affected by federal environmental regulations, the interaction with the necessary reliability reforms and their expected pace is of interest. The reverse is also true—reliability reforms needed for the changing grid, but not associated with coal retirements, are not directly affected by the implications of environmental regulations on coal plants. That is, these types of reforms will need to be pursued to ensure reliability with or without environmental regulations.

3. Grid reliability needs will continue to evolve and must be addressed regardless of environmental regulations

Different mixes of factors drive the various trends listed above. Environmental regulations have contributed directly to coal generation retirements by increasing the cost to operate some emission-intensive generation plants (such as plants without emissions controls). However, other factors such as clean technology cost declines, customer preferences, and state clean energy policies have also been, and will continue to be, major driving forces of coal retirements. We find that, with or without environmental regulations, other factors will continue to drive industry change and the need for reliability reforms. That is to say that when decisions are made to retire a generator, they are made based on the combined effects of all factors that impact the generator's economic outlook, any one of which could potentially make the difference on a retirement decision.

On the other hand, coal plant retirements (and their underlying causal factors, including environmental regulations) only indirectly affect other reliability needs, such as those related to operating reliability. This indirect effect is caused by the nature of the replacement resources, such as wind and gas generation, that backfill the retirements. While such retirements may accelerate deployment of these replacement resources, we find that other factors also play a major role. Such factors include cost declines for renewables and storage resources, customer preferences, and clean energy policies. Therefore, clean energy resources would significantly increase with or without federal environmental regulations. It follows that the effects of increasing penetration of clean energy resources on operating reliability would occur regardless of the potential impact of environmental regulations on coal plant retirements.

For all of these reasons, reliability needs will continue to change regardless of environmental regulations, and reform efforts across the four aspects of system reliability will need to be pursued either way.

4. Environmental regulations include compliance flexibilities as tools to help maintain reliable system operations

Despite being only one of many contributors to coal plant retirements, environmental regulations could accelerate the pace of such retirements. While many enabling technologies are available and the relevant reliability reforms are well underway, in the hypothetical case that the pace of coal retirements threatened to outrun the pace of relevant reliability reforms, it is instructive to understand what compliance flexibilities exist in environmental regulations to deal with such possibilities.

Environmental regulations typically specify standards for emissions (e.g., rates per unit of fuel use or quantities per hour or per year), compliance deadlines, and multiple compliance options with varying degrees of costs and effectiveness to reduce emissions. The various forms of compliance flexibilities allow plant owners, state regulators, and system planners to develop economical compliance plans designed to achieve overall environmental objectives while preserving system reliability. The key types of compliance flexibilities in U.S. federal environmental regulations that tend to reduce adverse impacts on electric grid reliability can be summarized into four general categories: (1) absence of an obligation to reduce generation output or retire a power plant; (2) multiple compliance options including emissions allowance purchases, fuel conversion and installation of control equipment that would allow power plants to continue operating during periods with high reliability needs; (3) multi-year advance notice to implement compliance plans; and (4) emergency exemptions as a last resort option for maintaining grid reliability.

I. Introduction

The future electric power grid is expected to undergo a major transition in the next decades, continuing a shift from fossil fuel-based systems of energy production to renewable energy sources and energy storage resources. Wind and solar generation together are expected to become the largest sources of power in more regions; battery storage deployments will see major growth; growth in electricity demand will accelerate; coal-fired generation will continue to retire; and there will be increasing grid regionalization and coupling.

On the supply side, these changes are expected to be driven largely by continued cost declines in renewable generation and battery storage, as well as policies and preferences to promote clean energy development. On the demand side, electrification of heating in buildings, proliferation of electric vehicles, and the expansion of new sources of demand from data centers, greenhouses, and other potential sources will offset much of the decline in demand from continued deployment of high-efficiency motor and lighting technologies.

While many of these specific conditions are new (or emerging) in the 21st century, they reflect patterns and trends that have been seen by the electric sector before. Throughout the industry's long history, electric companies, grid operators, and regulators have developed processes to maintain regional grid reliability in the face of changing conditions. These processes are being applied to the challenges facing the industry now.[4]

While environmental and public health regulations are cited as a driver of the ongoing changes to the resource mix and the resulting reliability effects, it is clear from our review that: (1) as a result of economic factors, customer preferences, and state clean energy policies, much of the ongoing transition of the power supply mix and the resulting changes to system reliability needs will continue to happen with or without the environmental regulations; and (2) planning for timely responses to the ongoing changes to the resource mix (including addressing the needs and utilizing existing and new tools noted below) will help maintain reliability.

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[4] The electric power system can be divided into the regional transmission system or grid, a network of interconnected high-voltage power lines and substations cross the country, versus the local distribution system which consists of local low-voltage circuits that connect customers to the larger grid. In this report, we focus on reliability on the regional transmission grid (also sometimes called the "bulk electric system"). This domain increasingly intersects with aspects of the distribution system, such as growth in demand and distributed resources. Nonetheless, we largely omit discussion of service interruptions due to local distribution outages, recognizing that this topic is an evolving field in its own right.

The bulk transmission grid is constantly evolving, and the institutions of the power sector are continuously learning, improving, and adapting. The evolution of the coming years will progressively shift the relative size and importance of today's challenges, but at a high level it is not likely to categorically transform them. As in the past, tools and processes to manage those challenges will need to evolve to match their changing nature, and innovations will need to build off prior developments. Likewise, new opportunities will emerge in line with the inherent capabilities of new resources coming online.

Some of these shifts are already evident, as follows:

EMERGING STRENGTHS

- Wide-scale nationwide deployment of solar will provide abundant energy coincident with the two or three peak hours of demand in late summer afternoons, significantly mitigating the challenge of meeting demand during such hours.
- Deployment of wind power, very significant in some areas, is expected to likewise provide abundant supply during many—although not all—extreme winter events (especially when properly winterized).
- Greater deployment of batteries, often installed to meet the tightest operational periods, will further deepen the pool of low-cost flexibility in the other hours of the year.
- High-voltage direct current (HVDC) transmission facilities can provide cost-effective access to remote renewable resources while contributing to system stability, providing many Essential Reliability Services, and relieving transmission congestion.
- Newly available grid-forming inverter technology, especially when backed by batteries, promises to provide all of the same Essential Reliability Services of conventional generators and synchronous condensers.
- Increasing deployment of flexible, internet-connected devices such as electric car chargers and heat pumps will provide the opportunity to tap into large quantities of the low-cost flexibility capabilities of demand.

CHANGING NEEDS

- **Capacity adequacy and long-term energy adequacy—**planning tools and processes must evolve in a variety of ways to accurately capture the reliability value of new technologies, improve regional coordination, and expand the transmission system's energy transfer capacity.

- **Operational energy adequacy—**the increase in variable wind and solar generation will drive greater variability and uncertainty in hourly supply, increasing the value of flexibility and the importance of the tools used today to manage variability and uncertainty in demand. Examples of such tools include operational forecasting,[5] forward scheduling tools,[6] expanded reserves products,[7] and expanded regional and interregional coordination.[8] In many cases, new reserve products such as ramping and imbalance reserves will need to be developed.[9]
- **Operating reliability—**displacement of conventional generators with inverter-based resources increases the importance of long-standing stability tools and provides opportunities to develop new tools. This is because spinning conventional generators naturally provide large quantities of stabilizing inertial response and dynamic voltage support, while inverter-based resources need to be specifically programmed to provide such capabilities. Existing stability tools to support reliability in this regard include generator control tuning, stability simulations, and installation of synchronous condensers where deemed preferable. New and emerging tools include the latest electromagnetic transient modeling and grid-forming inverter technology, among many others.

The purpose of this study is to explain the key needs and opportunities in maintaining reliable bulk transmission system operations in the evolving electricity industry through a review of historical and forward-looking evaluations of the industry. We explore key needs and summarize a series of reforms that grid operators, utilities, and regulators must undertake to be prepared for the coming energy transition. We explain how the necessary pace of different reforms may or may not be affected by specific industry changes, in particular coal retirements that may be influenced by new environmental regulations. We end by exploring specific considerations related to compliance flexibilities in environmental regulations to maintain grid reliability.

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[5] Southwest Power Pool (SPP), Markets+: A Proposal for Southwest Power Pool's Western Day-Ahead Market and Related Services, November 30, 2022, p. 31.

[6] California Independent System Operator (CAISO), Day-Ahead Market Enhancements and Extended Day-Ahead Market Tariff Amendment Docket No. ER-23-2686, August 22, 2023, p. 3.

[7] CAISO, Extended Day-Ahead Market (EDAM), 2023, p. 2.

[8] Western Energy Imbalance Market (WEIM), "How it Works," accessed December 11, 2023.

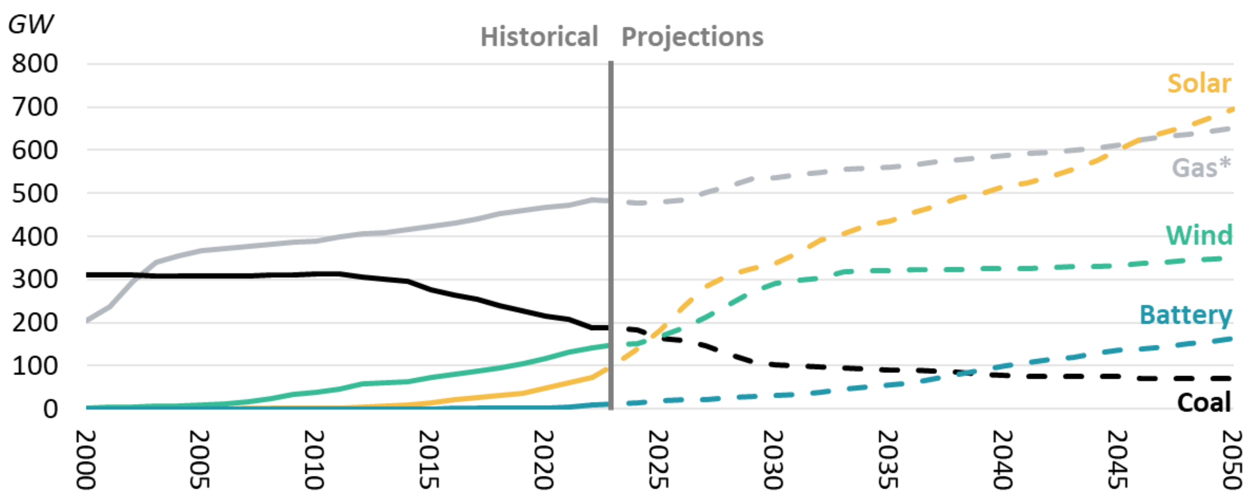
[9] CAISO, "Flexible Ramp Up and Flexible Ramp Down uncertainty awards in CAISO," 2016, accessed December 11, 2023.

II. Summary of Changes in the Electricity Industry

The electric power grid is expected to undergo a major transition in the next two decades, continuing trends that have brought about a shift from fossil fuel-based systems of energy production to increasing penetration of renewable energy and storage resources complemented by flexible electricity demand. Each trend in this transition is driven by distinct factors and results in different reliability effects. To understand the reliability effects of the changing grid and how they might be affected by various regulations, it is important to recognize the nature of the changes and why they are happening.

Wind and solar generation together are expected to grow more quickly, together becoming the largest source of power in more regions; battery storage deployments will see major growth; coal-fired generation is expected to continue to retire; electricity demand is expected to increase in many parts of the country; grid regionalization and coupling is expected to continue to increase; and extreme weather (especially cold weather) is expected to continue to have important reliability impacts.

FIGURE 1: HISTORICAL AND PROJECTED ELECTRICITY CAPACITY BY FUEL TYPE



Notes and Sources: *Under EIA Annual Energy Outlook projects, the category including "gas" combines capacity from combined cycle, combustion turbine/diesel, and natural gas/oil steam plants; capacity equal to installed summer capacity (for conventional generators) or nameplate capacity (for wind, solar, and battery resources) for use in the electric power sector; figure excludes capacity from conventional hydropower, nuclear, storage, geothermal, and biomass sources; see U.S. Energy Information Administration (EIA), Monthly Energy Review, 2023, Table 7.2b; EIA, Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 9, Table 16.

Figure 1 shows the historical and projected changes in capacity mix by technology from the U.S. Energy Information Administration (EIA) reference case outlook. These changes are expected to be driven largely by continued cost declines in renewable generation and battery storage, as well as ongoing policies and preferences to promote clean energy development. More coal retirements are expected due to continued past trends of competition from cheaper resources, increasing operating costs of an aging coal fleet, incremental costs to comply with environmental regulations, and clean energy policies.

On the demand side, growth is expected due to electrification of heating in buildings, expansion of electric vehicles, and the growth of new sources of demand from data centers, greenhouses, reshoring manufacturing, and other potential sources.[10] As a result, recent demand forecasts across the county show increasing expectations of growth, but they disagree on the extent to which new growth areas will offset the decline in demand from continued deployment of energy efficient technologies.

The growth in wind and solar deployment will continue to increase the amount of variability and uncertainty of supply on the grid, while at the same time providing abundant solar supply during summer peak demand hours and abundant wind supply during some (but not all) winter peak demand hours. In order to maintain reliability while taking advantage of this low-cost supply, grid operators will need to continue to enhance existing mechanisms designed to maintain reliability under variability and uncertainty; enhance traditional tools for evaluating the long-term adequacy value of new types of supply resources; and standardize protocols for integrating inverter-based resources into the alternating-current (AC) grid (as discussed in detail in Section IV).

Below we summarize six key trends of the energy transition. We provide additional details and data in Appendix A.

A. Increase in wind and solar generation

As shown in Figure 1 above, generation capacity of both wind and solar resources has greatly increased in the past two decades, with growth expected to continue at a faster pace throughout this decade. As of 2022, installed capacity of onshore wind surpassed 141 GW, while utility-scale

[10] In the long term, additional sources of demand could develop from hydrogen electrolyzers and carbon capture technologies including direct air capture.

solar reached 72 GW. By 2035, solar is projected to reach 435 GW compared to 320 GW of wind (see Figure 1).[11] This represents an expected annual growth rate of 16% (28 GW/year) for solar and 7% (14 GW/year) for wind between 2023 and 2035.[12]

Growth of wind and solar is spurred by several drivers: decreasing costs, continued federal tax incentives, and consumer preferences for clean energy. Between 2010 and 2022, capital costs for new solar installations decreased by 70% in nominal terms due to declining hardware costs and other economies of scale, as shown on the left side of Figure 2 below.[13] While capital costs for wind were essentially flat between the mid-2000s and 2022 (i.e., declining slightly in real terms), improvements in production efficiency significantly decreased per-MWh "levelized" costs for wind, as shown on the right side of Figure 2.[14] Levelized costs for solar have also declined however at a faster pace. Contract prices, which include the impacts of tax incentives, are lower than levelized costs, and they have decreased by 77% for solar and 52% for wind in nominal terms between 2010-2022.[15] Contract prices are expected to continue to decline between 2022 and 2035, due to technology improvements and increased efficiency in operation and maintenance.[16]

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[11] U.S. Energy Information Administration (EIA), Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 16.

[12] EIA, Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 16.

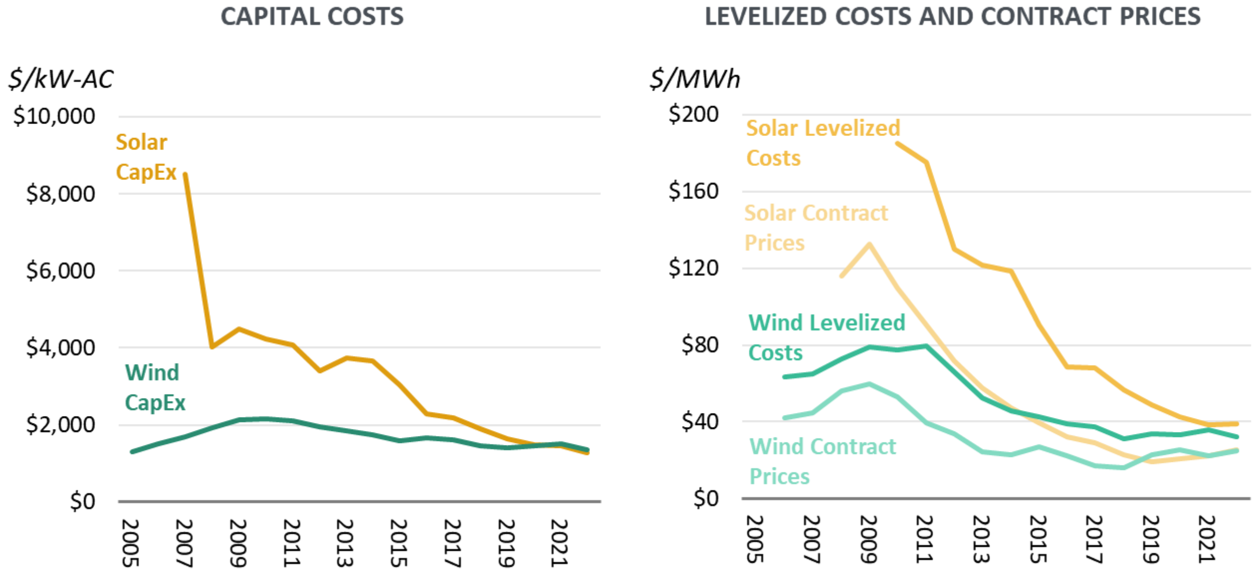
[13] Nominal dollar values. Lawrence Berkeley National Laboratory (LBNL), Utility-Scale Solar 2023 Edition Data File, October 2023, accessed December 4, 2023; U.S. Department of Energy (DOE), Land-Based Wind Market Report: 2023 Data File, 2023, accessed December 4, 2023.

[14] With capital costs "levelized" over the project life using appropriate discounting.

[15] Nominal dollar values. LBNL, Utility-Scale Solar 2023 Edition Data File, October 2023, accessed December 4, 2023; U.S. DOE, Land-Based Wind Market Report: 2023 Data File, 2023, accessed December 4, 2023.

[16] National Renewable Energy Laboratory (NREL), 2023 Electricity Annual Technology Baseline Data, 2023.

FIGURE 2: HISTORICAL SOLAR AND WIND CAPITAL COSTS, LEVELIZED COSTS, AND CONTRACT PRICES



Notes and Sources: Values all correspond to new wind and solar generators. Levelized costs and contract prices include both capital costs and ongoing operating costs. Levelized costs are a hypothetical fixed cost-per-MWh for a new wind or solar generator (not accounting for federal tax credits), with capital costs levelized across all energy production throughout a project's lifetime, with appropriate discounting of future value. Contract prices are average market-based contract prices from surveys and include impacts from tax incentives. Dollars are expressed in nominal terms; Lawrence Berkeley National Laboratory (LBNL), Utility-Scale Solar 2023 Edition, 2023; U.S. Department of Energy (DOE), Land-Based Wind Report, 2023.

Ongoing clean energy policies for wind and solar, such as the federal investment tax credit (ITC) and production tax credit (PTC), are slated to continue through 2032, with higher levels of tax credits available to projects that meet certain criteria.[17] These tax credits lower financial barriers for developers and therefore significantly support anticipated growth in these renewable resources.[18] Meanwhile, increasing consumer preferences for clean energy, especially by large municipal and corporate customers, will continue to encourage additional renewable development. In 2022, 5.7 million customers in municipal procurement programs purchased about 14.6 TWh of renewable energy (up from 0 TWh in 2010), while corporate buyers contracted

[17] Starting in 2025, the Clean Electricity Production Tax Credit and the Clean Electricity Investment Tax Credit will replace the PTC and ITC, with the main difference being that the Clean Technology PTC and ITC are open to all zero-emission generation facilities, unlike the technology-specific ITC and PTC. Projects that meet certain environmental justice criteria, such as being placed in a low-income community or located on indigenous land, are eligible for bonus tax credits. See U.S. Environmental Protection Agency (EPA), Summary of Inflation Reduction Act Provisions Related to Renewable Energy, 2023.

[18] John E. T. Bistline, et al., Power sector impacts of the Inflation Reduction Act of 2022, November 30, 2023.

with 3.3 GW of new wind and solar, amounting to approximately 17% of total new wind and solar installations in that year (19.9 GW).[19]

B. Ramping up deployment of storage resources

Energy storage technologies offer flexible and dispatchable capability that supports reliability without generating new emissions. These technologies, particularly battery storage, are currently undergoing a period of rapid deployment, going from under 2 GW in 2020 to 17 GW by the end of 2023.[20] Battery storage is expected to reach 30 GW by 2030 and over 50 GW by as early as 2035 (see Figure 1).

Key drivers of future battery storage deployment include continued cost declines of lithium-ion battery packs, the increasing value of flexibility and dispatchable capacity (particularly driven by solar penetration), and beneficial state and federal clean energy policies. The cost of lithium-ion battery packs has decreased by more than 63% in real terms between 2013 and 2022, as shown in Figure 3. Despite a slight recent price increase due to temporary supply chain constraints and a high inflationary environment, future battery storage costs are expected to continue to decline in the long term from approximately $479/kWh in 2023 to approximately $310/kWh by 2035 as shown in Figure 3 (Reference Case).

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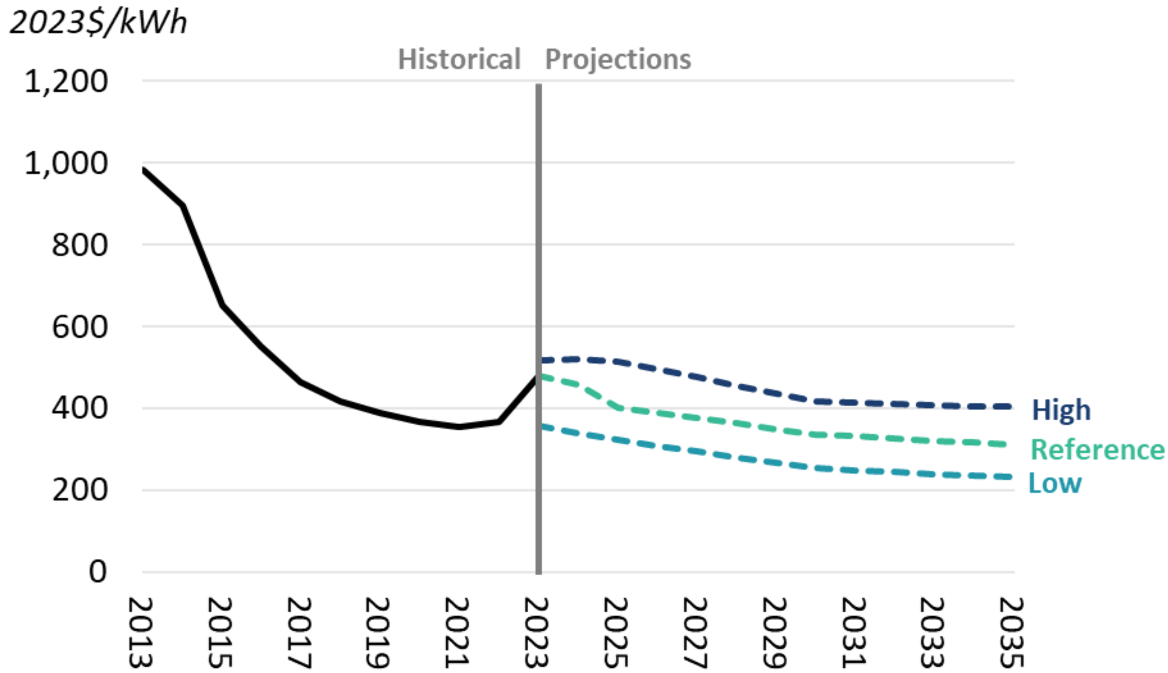
[19] Municipal procurement data from NREL, Status and Trends in the Voluntary Market (2022 Data), September 20, 2023. Installed capacity additions with corporate buyers from Clean Energy Power, 2022 Corporate Buyers Report, January 2023, p. 41; Total increase in wind and solar capacity in 2022 from EIA, Monthly Energy Review, 2023, Table 7.7b.

[20] 17 GW refers to planned battery storage capacity with online date in 2023, according to EIA Form 860M data; EIA, "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA 860)," November 22, 2023, October 2023 data, accessed November 28, 2023; EIA, "Electric Power Annual," 2023, Table 4.08. C. Usage Factors for Utility Scale Storage Generators, accessed November 28, 2023.

FIGURE 3: HISTORICAL AND PROJECTED COST DECLINES OF UTILITY-SCALE BATTERY STORAGE FACILITIES



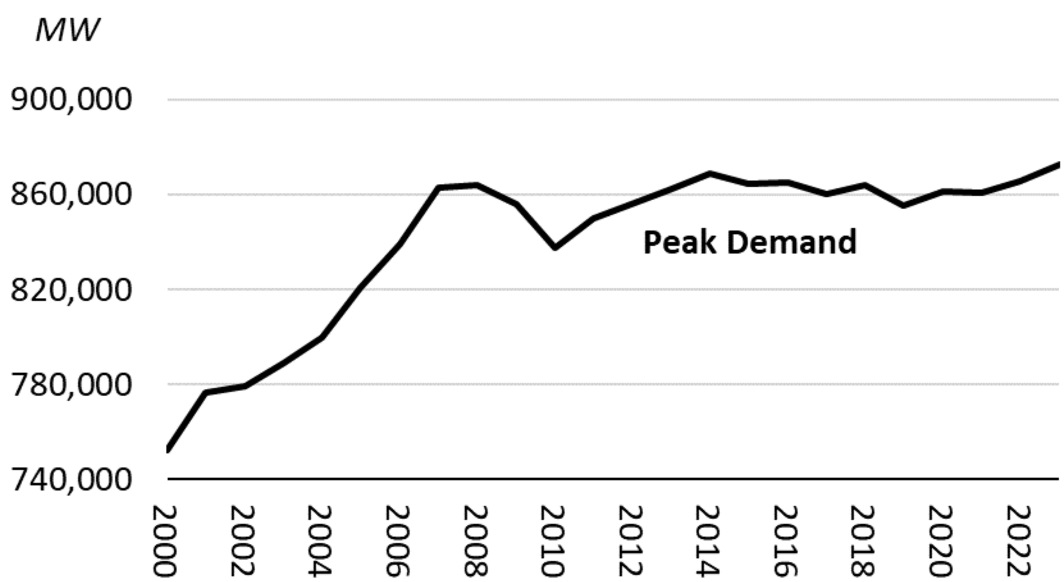
Notes and Sources: Historical data for battery facilities are based on Bloomberg battery pack cost estimates plus a cost-adder of $206/kWh in 2023$ which accounts for additional component (battery management systems, balance of system, inverters, etc.) and soft costs (taxes, overhead, developer costs, etc.) for the remainder of facility costs; projections of battery facility costs are National Renewable Energy Laboratory (NREL) 2023 Annual Technology Baseline (ATB) estimates for 4-hour, utility-scale lithium ion battery storage. See Bloomberg New Energy Finance (BNEF), "Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh," November 27, 2023, accessed November 28, 2023 and NREL, 2023 ATB, 2023.

C. Reversing flat electricity demand growth

Growth in peak demand for electricity has been low over the last two decades. Compared to the historical average national electricity peak demand growth rate of approximately 2.4% per year between 1980 and 2000, the average national peak demand growth rate between 2000 and 2023 was only 0.7% per year (and largely flat peak demand since 2008), as shown in Figure 4.[21]

[21] Peak demand growth prior to 2000 is calculated from North American Electric Reliability Corporation (NERC) historical peak load data while growth between 2000 and 2022 calculated from NERC near-term forecasts of peak load. See NERC, 1992 Long-Term Reliability Assessment, September 1992, p. 8; NERC, 2000 Long-Term Reliability Assessment, October 2000, p. 7; NERC, 2003 Long-Term Reliability Assessment, December 2003, p. 14.

FIGURE 4: HISTORICAL U.S. PEAK ELECTRICITY DEMAND



Notes and Sources: Data are historical near-term forecasts of peak demand; NERC, 2023 Long-Term Reliability Assessment, December 2023, Supplemental Charts and Graphs, Table F.

Future demand growth is expected to be driven by electrification of heating in buildings, expansion of electric vehicles, as well as the expansion of new sources of demand from data centers, greenhouses, reshoring manufacturing, and other sources (see Appendix A). Recent forecasts reflect a jump in expectations for growth, with significant regional variation as well as uncertainty regarding the extent of future demand growth that will materialize depending on the pace of decarbonization efforts and development of new sources of demand. For example, NERC forecasts an aggregate national summer peak demand of 0.98% growth on average annually over 10 years, up from 0.65% in 2022; grid operators PJM Interconnection (PJM), New York Independent System Operator (NYISO), and the Electric Reliability Council of Texas (ERCOT) are forecasting 0.8%, 0.9%, and 1.1% growth in summer peak demand, respectively. Additionally, several utilities now forecast annual peak demand growth in the range of 1.5% to 2.5%, with some greater than 4% (e.g., Dominion Energy in PJM).[22]

[22] NERC, 2023 Long-Term Reliability Assessment, December 13, 2023, Supplemental Charts and Graphs, Table H; NERC, 2022 Long-Term Reliability Assessment, December 15, 2022, Supplemental Charts and Graphs, Table H; PJM Interconnection (PJM) , Load Forecast Report, January 2023, p. 2; New York Independent System Operator (NYISO), 2023 Load and Capacity Data Report, April 2023, p. 2; Electric Reliability Council of Texas (ERCOT), System Planning: Long-Term Hourly Peak Demand and Energy Forecast, January 18, 2023, p. 2.; Arizona Public Service (APS), 2023 IRP Stakeholder Meeting, April 7, 2023, p. 29; PJM, Load Forecast Report, January 2023, p. 33-36; Puget Sound Energy (PSE), 2021 PSE Integrated Resource Plan, 2021, Chapter 6: Demand Forecasts, p. 6-5; Energy + Environmental Economics, Resource Adequacy in the Desert Southwest, February 2022; PSE, 2021

Since 2010, the majority of new homes are heated primarily with electricity.[23] Electrified heating is expected to have a major impact on annual peak demand, especially in many cold regions, which will cause these areas switch from summer to winter peaking systems. This seasonal peak switching has implications for reliability planning since traditional approaches have been focused on meeting summer peak load.

In 2023, over 8% of all light-duty vehicle sales were electric vehicles and further adoption is expected to be a significant driver of future total electricity consumption.[24] If electric vehicle adoption rates achieve stated federal and state goals, electric vehicle electricity demand could reach 100 TWh/year in 2030 (representing around 2% of total annual energy demand), rising to 930 TWh/year in 2050, or 20% of total estimated 2050 energy demand (see Appendix A).[25]

The commercialization of smart internet-connected technologies is expected to enable flexible demand or energy consumption that can be actively managed and controlled to complement variable renewable energy production and improve grid reliability.[26]

D. Continued coal plant retirements

From 2005 to 2022, U.S. coal capacity decreased from 321 GW to 219 GW (a 32% reduction) while energy output from coal generators decreased more steeply from 1,886 TWh to 665 TWh in that time (a 65% drop), as shown in Figure 5. The reduction in coal capacity corresponds to about 9%

PSE Integrated Resource Plan, 2021, Chapter 6: Demand Forecasts, p. 6-5; Georgia Power, 2023 Integrated Resource Plan Update, October 2023, p. 10.

[23] Lucas W. Davis, What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices, National Bureau of Economic Research (NBER) Working Paper Series, October 2023.

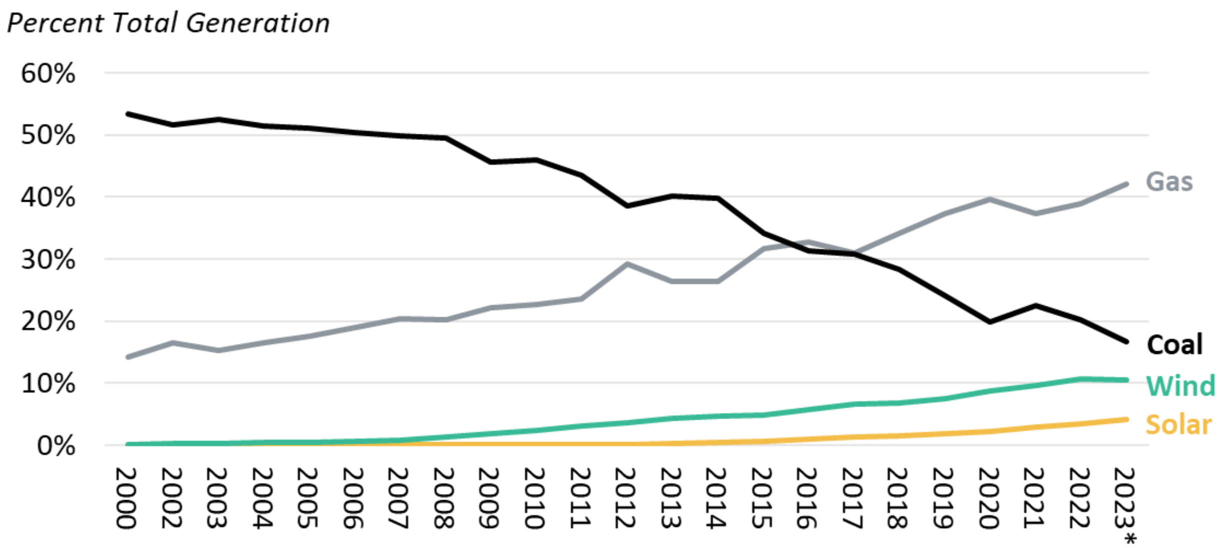
[24] Includes sales data through November of 2023. “Light-duty vehicles” includes cars and light trucks and “electric vehicles” include battery electric and plug-in hybrid vehicles. See Argonne National Laboratory, “Light Duty Electric Drive Vehicles Monthly Sales Update,” 2023, accessed November 29, 2023; Trieu Mai, et al., Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States, NREL, 2018.

[25] Based on NREL scenario whereby EV demand reaches 930 TWh/year in 2050 which reflects EV sales reaching 50% in 2030 and 100% in 2035. The former target is consistent with the national goal as set in the Biden Administration Executive Order and the latter target is aligned with several other state and non-federal targets; calculation of EV sales as percent of future load based on NREL projections of electric vehicle electric load compared to EIA forecasted electricity demand (Reference Case). See Arthur Yip, et al., Highly Resolved Projections of Passenger Electric Vehicle Charging Loads for the Contiguous United States, NREL, June 2023, pp. 22-23, 29-30; EIA, Annual Energy Outlook 2023, March 16, 2023, Table 54.

[26] Ella Zhou and Trieu Mai, Electrification Futures Study: Operation Analysis of U.S. Power Systems with increased Electrification and Demand-Side Flexibility, NREL, May 2021.

of total U.S. generation capacity. Coal plants are expected to continue to retire in the future with about 68 GW already announced for retirement by the end of 2030.[27] The EIA projects that coal capacity will decline to 91 GW by 2035, as shown in Figure 1.[28]

FIGURE 5: PERCENT OF ANNUAL TOTAL ELECTRIC ENERGY GENERATED BY FUEL TYPE



Notes and Sources: 2023 data represents net generation from January through August 2023; EIA, Monthly Energy Review, November 2023, Table 7.2b.

Coal plant retirements cannot be attributed to a single driver. Instead, coal plants are expected to continue to retire due to several concurrent, and in many cases, continued factors. These include competition from cheaper new resources, increasing operating costs of an aging coal fleet, and incremental costs to comply with environmental regulations. While new expectations of rising demand growth may improve financial prospects for all supply (including existing coal), retirement pressure is expected to continue, especially in states with net-zero carbon goals and other policies that envision a very limited or non-existent role for coal in the future, many of which still have substantial coal generation.[29]

E. Growth of centralized regional wholesale markets

In future years, many utilities across the U.S. are expected to join energy and capacity-pooling programs designed to standardize resource adequacy requirements as well as coordinate real-

27 Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

28 Note that this projection does not include the effects of the EPA's proposed 111(d) GHG rule.

29 For example, Maryland, Minnesota, Wisconsin, Illinois, New Mexico, and Colorado, see Clean Energy States Alliance, "Map and Timelines of 100% Clean Energy States," 2023, accessed December 13, 2023.

time and day-ahead procurement and dispatch of energy. Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) are regionalized wholesale markets that naturally enhance efficiency and reliability by providing more options across a large region to meet demand, especially peak demand. ISOs/RTOs schedule against more favorable daily profiles in demand and supply (especially wind and solar) due to geographic diversity across their footprints, thus inherently reducing flexibility challenges. While most of the growth of ISOs/RTOs occurred prior to the early 2010s, they continue to expand today (especially in the West).[30]

Recently, centralized wholesale energy markets known as Energy Imbalance Markets (EIMs) have been expanding in the West. The Western EIM (WEIM) was initiated in 2014 and now covers 22 control areas across ten states in the West and part of Canada.[31] Many WEIM stakeholders have committed to adding day-ahead generator scheduling functionality through the Extended Day Ahead Market (EDAM).[32] Similarly, the Western Energy Imbalance Service (WEIS) was initiated in early 2021, and is being further developed to incorporate day-ahead scheduling capabilities through the Markets+ effort.[33] Finally, the Western Resource Adequacy Program (WRAP), a capacity-based resource adequacy market, was approved by the Federal Energy Regulatory Commission (FERC) in February 2023 and will allow utilities in the West to pool capacity resources. Figure 6 below shows how these regional markets have expanded to cover most of the West.

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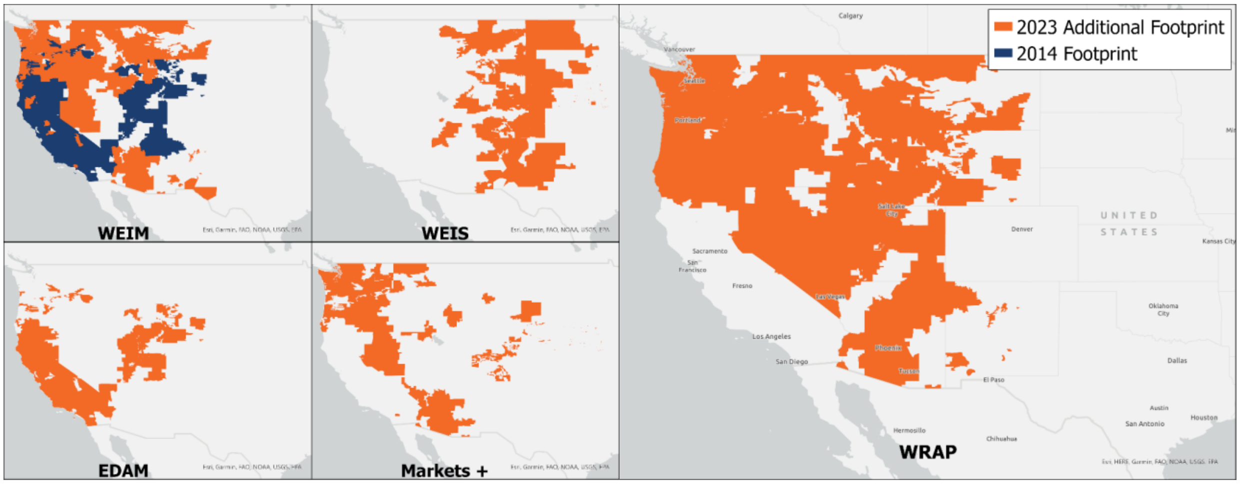
[30] SPP, "SPP RTO will expand with commitments from western utilities", September 14, 2023, accessed November 30, 2023.

[31] WEIM, "About," 2023, accessed November 28, 2023.

[32] CAISO, "Initiative: Extended day-ahead market," October 3, 2019, accessed November 30, 2023.

[33] SPP, "Markets+," accessed November 30, 2023.

FIGURE 6: GRID REGIONALIZATION PROGRAM FOOTPRINT: 2014 AND 2023



Notes and Sources: EIA, Electric Retail Service Territories, December 9, 2022, accessed November 30, 2023; WEIM, "About," 2023, accessed November 30, 2023; CAISO, "EDAM: Extended Day Ahead Market," accessed November 29, 2023; SPP, Western Energy Imbalance Service Market, 2023, accessed November 30, 2023; SPP, "Markets +," accessed November 30, 2023; Western Power Pool (WPP), "WRAP Area Map," April 5, 2023, accessed November 30, 2023.

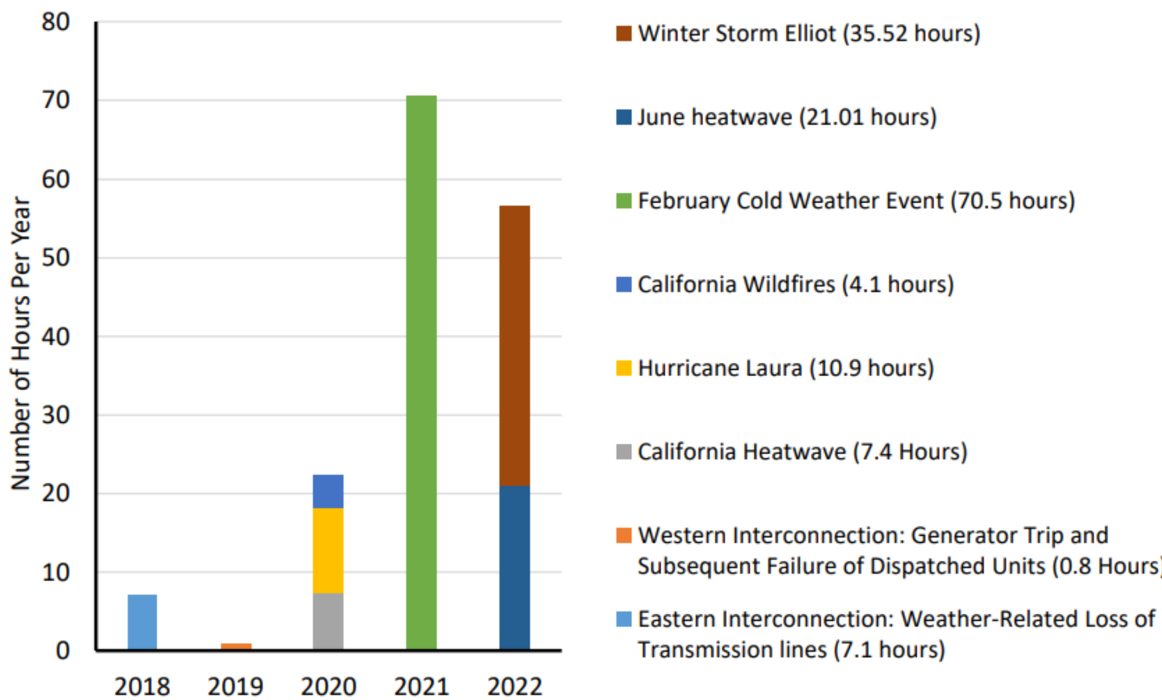
F. Rising impact of extreme weather events

The impact of both extreme hot and extreme cold weather events on power system reliability has been increasing due to several factors, including: higher frequency of generator failures during extreme weather (in many cases due to unavailability of fuel in cold weather, especially gas); steady increase in dependence on electricity for winter heating; increasing frequency and extent of hot weather events, and the resulting increase in drought and wildfire.[34] As shown in Figure 7 below, the number of hours of rotating outages that have been called in the U.S over the past five years have increased since 2019, with most of those hours caused by extreme cold weather events.

While reforms have been underway to mitigate these growing impacts (especially to improve and more accurately plan for reliability contributions of gas generation during extreme cold weather), the underlying drivers are expected to continue and in some cases grow. For example, gas generation capacity and electric heating are expected to continue to grow (though capacity factors are expected to drop at individual gas generating plants).

[34] NERC, 2023 State of Reliability Technical Assessment: Technical Assessment of 2022 Bulk Power System Performance, June 2023, p. 7.

FIGURE 7: HOURS OF ROTATING OUTAGE BY EVENT IN THE U.S. SINCE 2018



Notes and Sources: NERC, 2023 State of Reliability Technical Assessment: Technical Assessment of 2022 Bulk Power System Performance, June 2023, p. 39.

Extremely high air temperatures tend to stress the grid by increasing the demand for electricity due to cooling and air-conditioning equipment while at the same time decreasing the maximum output capabilities of some types of fossil fuel plants and the power capability of inverters.[35] Long droughts reduce the availability of water for hydroelectric plants and increase the frequency and impact of wildfires, which in turn can reduce the transfer capabilities on the affected transmission infrastructure.[36]

Extreme cold weather events have had a sporadic but major impact on reliability over the last decade. For example, due to generation outages caused by Winter Storm Uri in 2021, ERCOT was required to issue the most extensive rotating outages in U.S. history to shed over 20,000 MW of load.[37] In contrast to most controlled outages, these blackouts had a major social impact,

35 SMA Solar Technology AG, Sunny Boy/Sunny Tripower Temperature Derating, Version 1.5 Technical Information, accessed December 12, 2023.

36 Electric Power Research Institute (EPRI), Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches, December 1, 2022, p. 20; NERC, 2023 State of Reliability Technical Assessment, June 2023, p. 30.

37 Federal Energy Regulatory Commission (FERC) and NERC, Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States, November 16, 2021, p. 9.

resulting in over 200 deaths and tens of billions in economic losses.[38] During winter storms with extreme cold air temperatures, demand for electricity and natural gas increase due to increased use of space and water heating as well as due to greater home occupancy. Such extreme weather conditions have substantially decreased power plant generation capabilities in past events due to freezing equipment, fuel unavailability for gas-fired units, stockpile freezes at coal-fired plants, ice blockages in river systems interfering with thermal plant cooling and hydropower intakes, turbine blade icing at wind plants, and snow cover at solar plants.[39]

Because winter events cause especially severe reliability impacts, they have been given special attention from FERC and NERC, who have developed new standards to address various concerns.[40] With a greater proportion of gas generation in the current resource mix, cold weather-related outages to gas plants have become more impactful on the electricity system and highlight the need for better winterization of generation equipment and improved coordination between the gas and electricity sectors (see Section IV.D).

III. Defining Reliability

We define regional (i.e., bulk transmission system) electric grid reliability as **the ability to ensure electricity is continuously available.** Based on NERC definitions (further elaborated in Appendix B), we focus on four aspects of reliability:

- **Capacity adequacy**, met when there are sufficient generation resources and transmission facilities installed to meet peak demand[41]
- **Long-term energy adequacy**, met when installed generation resources and transmission facilities are sufficiently available and have the necessary attributes like flexibility and

[38] FERC and NERC, Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States, November 16, 2021, p. 10

[39] EPRI, Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches, December 1, 2022, p. 20.

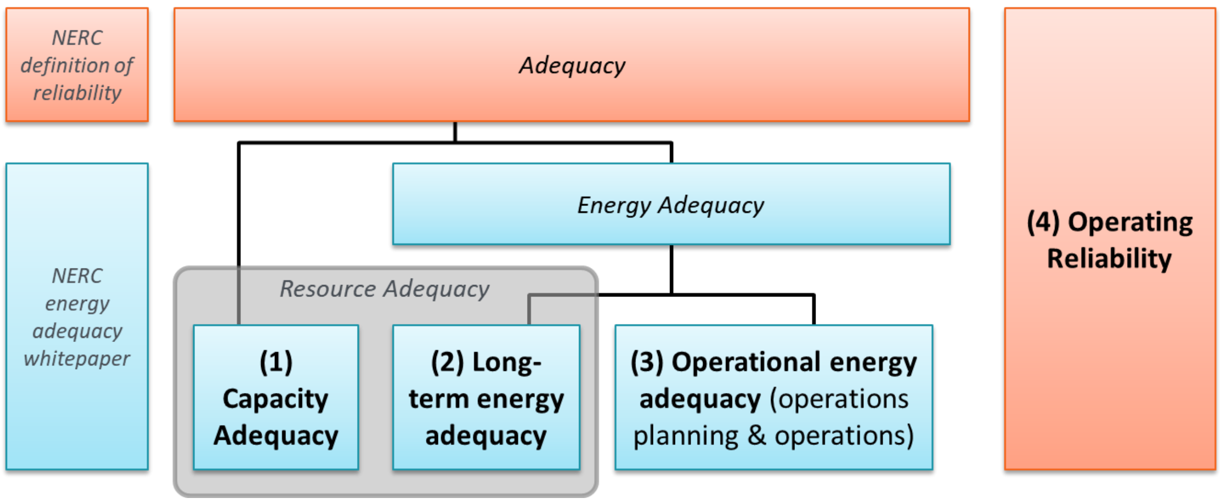
[40] FERC, "FERC Approves Extreme Cold Weather Reliability Standards, Directs Improvements," February 16, 2023, accessed December 5, 2023.

[41] NERC sometimes uses the more general term "resource adequacy" to refer to capacity adequacy, see NERC, ERO Reliability Assessment Process Document, April 2018, p. 9, 10.

sustained output to meet demand in every hour of the year (a planning concept with renewed attention recently) [42]

- **Operational energy adequacy**, met when supply and demand are continuously balanced in real-time even under uncertainty and large fluctuations in supply and demand
- **Operating reliability,** met when the electric grid sustains sudden disturbances and can recover to normal operations quickly[43]

FIGURE 8. THE FOUR ASPECTS OF RELIABILITY AND THEIR RELATIONSHIP TO OTHER DEFINITIONS



Notes and Sources: NERC, Reliability Terminology, 2013; NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December 2020.

Traditionally, resource adequacy assessments have focused on **capacity adequacy**. However, the evolving resource mix places heightened importance on **long-term energy adequacy**. Long-term energy adequacy is concerned with investments in a resource fleet and transmission network that can meet demand under all kinds of conditions. Assessments of long-term energy adequacy could include evaluations of potential widespread generator failures, sustained periods of low

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42 NERC equates energy adequacy with "*more advanced probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy*" and "*assessment of resource adequacy across all hours.*" See NERC, 2020 Long-Term Reliability Assessment, December 2020, pp. 9, 23.

The NERC Energy Reliability Assessment Task Force (ERATF) is currently developing definitions and standards related to energy adequacy. See NERC, Energy Reliability Assessment Task Force Scope, February 2021.

43 NERC defines "adequacy" and "operating reliability" as the two aspects that define reliability. See NERC, Reliability Terminology, August 2013, accessed November 9, 2023.

NERC further differentiates capacity adequacy, long-term energy adequacy, and operational energy adequacy in NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December, 2020, pp. 3-4.

wind and solar availability, and the limited energy storage capabilities of batteries and hydropower generators.[44]

NERC has proposed to distinguish **operational energy adequacy**, which covers shorter timeframes (including both shorter-term operations planning and real-time operations), from **long-term energy adequacy**, which covers a timeframe of one or more years.[45] Operational energy adequacy refers to the careful orchestration, planning, and execution of day-to-day operations in order to balance supply and demand.[46] Such balancing is a perennial challenge due to the physical need to instantaneously match supply and demand on the electric grid.[47]

NERC's second aspect of reliability, **operating reliability**, is the ability of the grid to recover from sudden disturbances. It therefore has a relatively narrow scope that belies its name.[48] Operating reliability is intimately connected to the physics of AC electric power systems, and plays out on the timescale of milliseconds to minutes. It is assured through redundant system operations (called "N-1" or security-constrained operations) to ensure transmission lines are not overloaded and to avoid cascading failures, together with development, procurement, and/or monitoring of key system attributes.

The term "Essential Reliability Services" refers to the set of system attributes or resource capabilities that facilitate operating reliability together with the set of resource capabilities that facilitate operational energy adequacy.[49] Most Essential Reliability Services are secured on an

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[44] NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December 2020, p. 1.

[45] Respectively, these shorter timeframes are known as the operations planning time horizon and the real-time operational time horizon, see NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December 2020, pp. 1, 3-4.

These are consistent with NERC's Time Horizons, see, NERC, Time Horizons, May 31, 2023.

[46] NERC defines "long-term planning" as a planning horizon of one year or longer. NERC's remaining time horizons are: operations planning (seasonal through day-ahead), same-day operations, and real-time operations (within the hour). See NERC, Time Horizons, May 31, 2023.

[47] Balancing is the sole goal of NERC's resource and demand balancing (BAL) series of standards, and is also a key goal of multiple transmission operations (TOP) standards. Nearly all of these standards are targeted at the operations planning, same-day operations, and real-time operations time horizons.

[48] NERC had previously referred to this aspect as "security," but renamed it to "operating reliability" following the events of September 11, 2001 in order to avoid confusion with the need to protect critical infrastructure against intentional attacks. See NERC, Definition of Adequate Level of Reliability, 2007, p. 5.

Despite the title, many aspects of reliable operations are not directly related to disturbances (e.g., balancing during normal operations), and so do not fall under "operating reliability." See NERC, Reliability Terminology, August 2013.

[49] NERC, Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014. These are described in detail in Section IV.C.

ongoing basis as "ancillary services", which exhibit varying degrees of standardization across the industry. For example, under NERC requirements, all grid operators support operating reliability using an ancillary service called "contingency reserves." Generators and other resources that provide contingency reserves must be capable of rapidly increasing supply (or decreasing demand) to maintain operating reliability following the sudden loss of a large generator. Under common usage, all ancillary services are classified as Essential Reliability Services.[50] When an Essential Reliability Service is not explicitly procured (e.g., as is typically the case now for inertial response), it is generally not considered an ancillary service. Emerging needs to actively manage the level of Essential Reliability Services on the system will necessitate the addition of new ancillary services to support operating reliability.

Together, the four key aspects of reliability (**capacity adequacy**, **long-term energy adequacy**, **operational energy adequacy**, and **operating reliability**) describe the past and future of grid operations and planning.

[50] DOE, Office of Energy Efficiency & Renewable Energy, Keeping the Lights On: Essential Reliability Services, September 13, 2018.

TABLE 1: CATEGORIZING FOUR KEY ASPECTS OF RELIABILITY

Aspect of Reliability	Objective	Typical Solutions
Capacity adequacy	Ensure sufficient power capacity of the installed fleet of resources to meet peak demand	• Utility Integrated Resource Planning • Capacity markets or capacity adequacy requirements • Evaluation and accreditation of capacity adequacy value of resources by evaluating availability during peak period
Long-Term Energy Adequacy	Ensure sufficient attributes of the installed fleet to meet system needs at all times	• Many parts of the analysis utilize year-round modeling (e.g., Effective Load Carrying Capability for calculating adequacy value, hourly analysis for identifying the resource requirement, and overall adequacy metrics) • Similar solutions to capacity adequacy, but with enhanced modeling (e.g., production cost modeling)
Operational Energy Adequacy	Schedule sufficient flexibility, sustained output capability, and other attributes to instantaneously match supply to demand, given variability, uncertainty, and transmission constraints	• Ancillary services such as regulation, load- following reserves, and new ramp reserves (together with corresponding NERC standards) • Optimized daily schedules of generators, storage resources, and other resource types
Operating Reliability	Avoid rapid cascading failures that lead to uncontrolled and widespread blackouts	• Grid codes specifying dynamic response of inverter-based generator controllers (e.g., Institute of Electrical and Electronics Engineers (IEEE) 2800) • N-1 operations • Essential Reliability Services such as inertial response, frequency response, and voltage regulation, as well as ancillary services such as contingency reserves

Notes and Sources: Integrated Resource Planning is a standardized process utilized by state regulators to help utilities develop prudent resource investment decisions.

A related concept to reliability (but currently less well defined and measured for developing specific targets) is **resilience**. To draw the contrast between reliability and resilience, the section titled "Resilience to Extreme Events" in the 2023 NERC Reliability Risk Priorities Report states that:

> *"BPS [bulk power system, i.e. the transmission grid] reliability involves performance consistency under various reasonably expected known or historical operating conditions. Resilience, on the other hand, involves the ability of the BPS to absorb and recover quickly from significant abnormal conditions or extreme events. Put simply, resilience involves BPS risks with the potential to affect a broad geographic area and last an extended time…Recent cold weather events (like in ERCOT, MISO, and SPP) as well as heat events, such*

> *as the 2020 California event, underscore that extreme events pose challenges due to their nature, breadth, duration, and frequency."*[51]

When disruptive events that have not occurred in the historical record take place, they often have not been explicitly planned for. A resilient grid can tolerate a variety of such events, while another grid that is not resilient but that otherwise has identical reliability planning metrics might perform poorly.

The term "resilience" can touch on each of the four aspects of reliability described in this report (i.e., capacity adequacy, long-term energy adequacy, operational energy adequacy, and operating reliability). As described below, grid operators are pursuing a variety of critical measures to improve reliability under extreme conditions and improve recovery from disturbances. These generally fall under both the "reliability" category and the "resilience" category. For example, see the discussion of gas generation winterization and gas-electric coordination in Section IV.D, and the discussion of operating reliability in Section IV.C.

IV. Achieving Reliability in the Past and Future Grid

Each of the trends described in Section II has a different effect on reliability, providing new capabilities and shifting reliability needs. In this section, we identify these shifting capabilities and needs, and describe technologies and reforms that have been designed to efficiently ensure reliability through the transition. We conclude by identifying how these reforms would or would not need to change if the underlying trends moved quicker due to changing drivers, for example new environmental regulations that could result in accelerating the retirements of some existing fossil plants.

The power sector has accumulated many decades of experience developing and utilizing tools to manage reliability. With the shifting resource mix, evolving demand patterns, and growing impact of extreme weather, reliability needs have changed. Industry players have pointed to a range of such changes, from new pressures on adequacy to the need to properly configure generator controls. Grid operators have therefore introduced an array of reforms and adaptations to their

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[51] NERC, 2023 ERO Reliability Risk Priorities Report, August 17, 2023.

tools to optimize use of new reliability capabilities and meet the emerging reliability needs. In some cases this involves bringing old ideas to the fore (such as optimizing the schedules of storage resources or using "effective load carrying capability" analysis, defined below), and in other cases developing new technology (such as grid-forming inverters).[52]

There is good reason for cautious optimism. These reforms have been designed to solve the coming reliability challenges, building off decades of categorically similar problems and solutions. They comprehensively cover every aspect of reliability. On the other hand, adapting to meet changing reliability needs is contingent on continued action from grid operators, utilities, regulators, and other stakeholders to develop and implement reforms. Such action must proceed at a pace that matches that of the changing grid. In some cases, reforms require institutions to take on new roles, new authority, or otherwise make important and potentially difficult adaptations. Failure to prioritize timely and comprehensive action can lead to reliability problems, even when technology and solutions are well established. For example, a recent NERC report points to degraded grid reliability simply because inverter-based resources have been configured with improper settings. Whether the needed reforms can be pursued at the requisite pace is therefore an important question.[53] Here too, there is reason for optimism. Grid operators across the country, whether ISOs/RTOs or standalone utilities, have been implementing and pursuing numerous fundamental reforms, with many examples documented below. To return to the example of inverter settings, NERC recently recommended changes to its standards to ensure uniform performance requirements, and FERC has recently ordered NERC to use its enforcement powers to ensure inverter settings are correctly configured.[54]

We begin by exploring five key reliability needs, relating these to the reliability effects of past and future changes in the electricity industry. In each case, we note how existing and emerging tools

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[52] Schedules for pumped hydropower storage resources have been centrally optimized for multiple decades in PJM and other grid operators.

[53] NERC, Inverter-Based Resource Performance Issues Report: Findings from the Level 2 Alert, November 2023.

[54] "*NERC recommends that all IBRs [inverter-based resources, i.e. wind, solar, and batteries], both BES and non-BES, have parameterized protection settings outside of the "no trip zones" based on maximum equipment capabilities so they don't trip when they are needed to remain on the system to preserve reliability…These settings show that numerous BES-connected facilities are at an elevated risk of tripping during BPS disturbances, are not setting their protections based on maximum equipment capabilities, and not following NERC guidance.*" NERC goes on to recommend "*enhancements to FAC-001* [a mandatory NERC reliability standard] *to ensure that sufficient uniform performance requirements are established by industry to mitigate these risks moving forward.*" See *Ibid.*

Among other things, FERC Order 901 requires NERC to establish reliability standards and use its enforcement powers to prohibit the misoperation of new and existing inverter-based resources. See FERC, 185 FERC ¶ 61,042, October 19, 2023, Reliability Standards to Address Inverter-Based Resources.

can be utilized and reformed to maintain reliability through the grid transition, with the use of examples of on the ground practices in place today. We also highlight several new or evolving technologies which feature enabling capabilities that will be needed more in the future.

A. Long-term energy adequacy under a new resource mix and extreme weather

RELIABILITY NEED FOR LONG-TERM ENERGY ADEQUACY

Mechanisms to ensure sufficient new resources replace retiring generation and meet growing load must be in place (and long have been in place) so that the power system does not suffer undue rolling blackouts. Energy adequacy requires both that the resource fleet can meet peak demand periods, but can also meet other periods that might experience shortfalls, for example in cold weather if many resources are not available to meet increased demand.

Long-term energy adequacy requires mechanisms to identify and forecast the adequacy need ahead of time; meet the need through resource investments; and measure actual adequacy on a regular basis to make adjustments as needed.

UNDERLYING TRENDS DRIVING THE SHIFT TO ENERGY ADEQUACY PLANNING

Growth in wind, solar, storage, and flexible demand tend to increase the abundance of supply during peak demand hours, decreasing the importance of peak demand as a focus of long-term adequacy planning. At the same time, wind and solar exhibit variable capability according to weather, and extreme winter presents vulnerability of failure for all resource types (in some cases, especially gas generation). The displacement of coal plants by wind, solar, batteries, gas, and flexible demand amplifies the importance of hours in which the new resource types are not available (e.g., summer evenings for solar, extreme cold winters for gas, and extended periods of low wind and solar for the combination of wind, solar, and battery storage).

This reliability need is therefore sensitive to: (1) the potential for further acceleration of the current trend of coal plant retirements due to headwinds such as higher costs to comply with new environmental regulations, deteriorating economics from aging equipment, and market competition; as well as (2) increases in overall demand that are met with incremental investments in new resource types.

GAPS IN LONG TERM ENERGY ADEQUACY PLANNING

NERC and other industry observers have expressed concern that, with shifts in the resource mix, existing planning mechanisms may not detect important failure modes to sufficiently ensure long-term energy adequacy.[55] The shift is related to two different effects: (1) the abundance of renewable resource output during peak demand hours, which shifts potential adequacy risks to other, non-peak hours; and (2) failures of many resource types (in many places especially gas) during extreme winter events, which shifts potential adequacy risks to those (often non-peak) hours. Both of these effects are in the domain of "energy adequacy."

If all resources were able to reach maximum power output almost all the time, a focus on peak demand as a planning metric for capacity adequacy could be appropriate. To the extent that many resources are frequently unable to reach their maximum power capability during critical times, e.g., due to widespread generator failures, fuel unavailability, inflexibility, low wind or solar output, or limited energy storage capabilities, a focus only on peak demand periods increasingly risks missing important periods of potential shortfall. Because conventional planning mechanisms have been focused on capacity adequacy, and therefore only on periods of peak demand, they may miss risks associated with non-peak periods.

For example, a summer-peaking system with ample capacity adequacy may have undetected shortfall risks associated with cold winter conditions in which many generators are unavailable due to widespread failures. During cold weather conditions, gas-fired generators may be unable to secure fuel because they lack firm contracts and/or home heating requirements take precedence in gas delivery; improperly winterized gas and renewable generation could be producing below their normal levels; yet electricity (and gas) demand could be high due to greater home occupancy (but below the annual peak). Such a system might exceed capacity adequacy requirements based on the single peak hour in a summer month, but fail to meet long-term energy adequacy requirements related to other hours, such as in winter.[56] Recent system emergencies have amplified this concern, for example winter emergencies in PJM and MISO; winter rotating outages in ERCOT, SPP, and the Southeast (mostly summer peaking systems); and summer rotating outages in the California Independent System Operator (CAISO) and the

[55] NERC, 2021 Long-Term Reliability Assessment, December 2021, Key Findings 3 and 5; EPRI, Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches, December 2022.

[56] NERC, 2021 Long-Term Reliability Assessment, December 2021.

Southeast. In some of these cases, particularly in the PJM and Southeast events, installed supply exceeded target levels.[57]

NERC underscores the importance of this change:

> *"It is now insufficient to assume that the system is adequately planned by comparing the peak load hours with the generation capacity. Assessments must look at the magnitude, duration, and impact of resource adequacy across all hours and many years while considering that future events may be outside of historical patterns."*[58]

Various shortcomings could lead to poor long-term energy adequacy, such as failure to add energy adequacy planning to existing capacity adequacy planning mechanisms, overestimating the energy adequacy value of generation and storage resources, or the inability of existing mechanisms intended to attract investment in new resources to adapt to new reliability needs.

Adequacy mechanisms that focus only on incentivizing capacity can attract new generation resources without adequately ensuring that those resources will be able to generate energy when needed. System needs for energy can vary by geographic location and over time based on the resource mix, transmission interconnectivity to surrounding regions, and local weather patterns, so adequacy mechanisms need to be sufficiently adaptable to incorporate each jurisdiction's unique features.

Systems that have adequate capacity but lack the flexibility to accommodate expected (as opposed to unexpected or uncertain) changes in hourly output of wind and solar do not necessarily suffer primarily from a reliability problem, but rather largely an economic problem associated with potentially undesirable curtailment, as discussed further in Section IV.B below. This is because the inflexible resources can be operated as needed to supply power during the tightest periods, while any potential excess supply created as a result is handled by curtailing the (very flexible in the downward direction) variable wind and solar output in the preceding periods.

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57 NERC, 2023 State of Reliability Technical Assessment: Technical Assessment of 2022 Bulk Power System Performance, June 2023, pp. 7-11, 39; NERC and FERC, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, October 2023, p. 13 and FN 40.

58 NERC, 2023 ERO Reliability Risk Priorities Report, August 17, 2023.

With rapid deployment of gas, renewables, and more recently storage resources, grid operators are in various stages of reforms to ensure sufficient long-term energy adequacy. Grid operators in the most advanced stages of resource mix transition have gone through successful adaptations of many of the pre-existing protocols and methods, as well as introduction of new protocols, in order to suit the new stringencies of energy adequacy planning. The most fundamental of these reforms is the introduction of energy adequacy into long-term resource planning. Every ISO/RTO and many standalone utilities have either accomplished this, or are in the process of developing it, through a method called Effective Load Carrying Capability (ELCC), described below.[59]

Reliability planning tools for ensuring long-term energy adequacy are well established. These tools are being newly harnessed via enhancements to ensure long-term energy adequacy in all hours of a year. The most widespread of such enhancements is the incorporation of ELCC and conceptually related analyses into long-term planning.[60] ELCC is a method to calculate the long-term adequacy value of a resource given patterns in its output relative to patterns in adequacy risk in all hours of the year. ELCC is itself a well-established method, though it has not been widely deployed until recent years as interest has grown in tools for long-term energy adequacy.[61] Many ELCC analyses take into account weather dependency of renewables and thermal resources as well as energy storage limitations of batteries and hydro, with detailed accounting for emergency procedures including demand response and other flexible demand. They utilize several decades

[59] Except ERCOT, which does not do centralized long-term adequacy planning. See, Tongxin Zheng, Resource Capacity Accreditation (RCA) Overview and Roadmap, ISO New England (ISO-NE), October 2023; California Public Utilities Commission (CPUC), Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026), June 24, 2021, p. 13; PJM, "Effective Load Carrying Capacity (ELCC)," accessed November 29, 2023; CPUC, 2020 Qualifying Capacity Methodology Manual, November 2020, pp. 13-14; MISO, "Planning Year 2022-2023 Loss of Load Expectation Study Report," 2022, accessed December 2, 2023, pp. 19-20; Astrapé Consulting, Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study, April 25, 2022, pp. 4-18; Georgia Power, 2023 Integrated Resource Plan Update, October 2023, p. 12; Arizona Public Service Company, 2023 Integrated Resource Plan, November 2023, p. 66; Public Service Company of Colorado, Our Future Energy: Destination 2030, March 31, 2021, p. 213-214; Astrapé Consulting, Dominion Energy South Carolina 2023 Planning Reserve Margin Study, January 27, 2023, p. 28; Tennessee Valley Authority, 2019 Integrated Resource Plan Volume I: Final Resource Plan, 2019, pp. D-7 – D-9.

[60] For general background on ELCC see Nick Schlag, et al., Capacity and Reliability Planning in the Era of Decarbonization, Energy + Environmental Economics, August 2020. For detailed information on ELCC calculations and conceptually related studies, see Astrapé Consulting, "Our Publications," 2023, accessed December 17, 2023.

[61] L. L. Garver, Effective Load Carrying Capability of Generating Units, IEEE Transactions on Power Apparatus and Systems, Aug. 1966, vol. PAS-85, no. 8, pp. 910-919.

of weather data to identify the worst-case concurrences of sustained low wind, low solar, unavailable thermal, and high demand.

Because the presence of wind and solar tends to shift peak net demand (meaning peak demand minus variable wind and solar output) and reliability risk to hours with less wind and solar, an energy adequacy value analysis like ELCC better measures the diminishing adequacy value of those resources with higher deployments, all else equal. With ELCC analysis informing investment decisions, greater deployment of variable resources results (in principle) in incremental displacement of fewer and fewer resources from the remainder of the fleet, including ultimately displacing close to none when the ELCC value of incremental additions approaches zero, as is the case for solar in California today.[62] Because this effect occurs even at modest deployment levels, grid operators tend to implement ELCC fairly early in the transition to renewables. ELCC has therefore been implemented or is under consideration (for at least a subset of resource types) in all of the ISOs/RTOs, as well as at many non-ISO/RTO utility grid operators. In addition, ELCC approaches can capture the adequacy impact of synergies between certain resource types, for example the increased adequacy value of additional storage (up to a certain level) in a solar-heavy resource mix due to storage's ability to flatten the shortened afternoon net load peak created by solar generation (see Figure 28 in Appendix A).

The hourly model of supply and demand that underpins ELCC can also serve as the core model for long-term adequacy planning generally.[63] NERC has used such assessment in its Long-Term Reliability Assessments since 2020, and is proposing to require them.[64] A complete reform to the long-term energy adequacy construct would be to use an hourly model as a common standard for the purposes of: assessing the adequacy contribution of resources of all technology types (e.g., via ELCC); setting the required aggregate procurement of adequacy resources; and performing overall assessments and calculating long-term adequacy metrics. Such a comprehensive energy adequacy reform has been proposed in PJM, and is currently being discussed at MISO and ISO New England.[65] Other ISOs/RTOs mix traditional capacity adequacy planning and energy adequacy planning methods.

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62 For example, see Astrapé Consulting and Energy + Environmental Economics, Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update), January 2023.

63 NERC, Considerations for Performing an Energy Reliability Assessment: ERATF White Paper, March 2023, pp. 1-3.

64 NERC, 2020 Long-Term Reliability Assessment, December 2020; NERC, 2022 NERC Probabilistic Assessment (ProbA), June 2023.

65 PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, Docket No. ER24-99-000; Midcontinent Independent System Operator (MISO), Resource

Energy adequacy models offer the opportunity to account for the effect of extreme weather on generator availability, capturing the reliability challenges associated with coincident outages under very hot or cold weather and procuring additional supply reinforcements to avoid or mitigate emergencies. With the growing impact of such events, such mitigation measures are increasingly important. In a list of "*general actions for industry and policymakers to address*" in its 2022 Long Term Reliability Assessment (LTRA), NERC makes this recommendation: "*Include extreme weather scenarios in resource and system planning.*"[66] Energy adequacy constructs that account for extreme weather impacts across all resource types (not just intermittent ones) are better able to ensure reliability, since many resource types exhibit higher failure rates under such conditions. For example, in cold weather, wind turbines and coal piles can freeze; ice blocks can form in rivers, jamming thermal generator cooling and hydropower intakes; and gas plants can fail or lose access to fuel.[67] Thus far, only PJM has proposed to capture the effect of the most extreme weather on availability of all resource types. ISOs/RTOs often use availability patterns from just one or a few recent years to estimate availability of certain resources under energy adequacy shortfalls, including during extreme weather, even if those recent years did not exhibit extreme weather.[68]

Examples of long-term energy adequacy reforms include:

- The California PUC (CPUC) has been required by law since 2011 to assess future adequacy across all hours of the year using an Effective Load Carrying Capability model that simulates the time-varying capabilities of wind and solar.[69] The result is fed into the resource investment mechanism so that both capacity adequacy and some features of long-term energy adequacy are addressed in the installed resource mix.[70] The CPUC separately assesses the flexible ramp capability needed in the long term to accommodate low-cost solar generation, and initiates investments to address any shortfalls, thereby securing another key

Accreditation White Paper Version 1.1, November 2023; Tongxin Zheng, Resource Capacity Accreditation (RCA) Overview and Roadmap, ISO-NE, October 2023.

66 NERC, 2022 Long-Term Reliability Assessment, December 2022, p. 7.

67 For ice jamming concern, see SPP, Southwest Power Pool's Response to the December 2022 Winter Storm, April 17, 2023, p. 7. For other winter issues, see FERC, FERC, NERC Release Final Report on Lessons from Winter Storm Elliott, November 7, 2023.

68 For example, current MISO resource accreditation for thermal resources is based on average performance during high risk hours from the previous three historical years. See MISO, Business Practice Manual 11, October 1, 2023, Appendix Y.

69 California Senate, Senate Bill No. 2, April 12, 2011.

70 CPUC Energy Division, Reliability Filing Requirements for Load Serving Entities' 2022 Integrated Resource Plans - Results of PRM and ELCC Studies, July 29, 2022.

aspect of long-term energy adequacy.[71] Following the rotating outages during the excessive heat of summer 2020, CAISO pursued efforts to add new resources to planning, accelerate deployment rates, and improve resource-specific operations.[72] CAISO pointed to the lack of rotating outages during a severe heat wave in September of 2022 as evidence of successful implementation of these efforts.[73]

- Motivated in part by a series of winter emergencies, and in part by an expected influx of renewables and storage, PJM has recently proposed reorienting their entire adequacy modeling construct around hourly assessment of system capabilities in light of many resource limitations. This model determines key capacity market parameters such as the long-term adequacy requirement and the adequacy contribution of each resource. The new construct evaluates all hours of the year, and simultaneously takes into account the likelihood of widespread generator failures, fuel unavailability, wind and solar output patterns, and energy storage resource capabilities.[74] In that way, it addresses the kinds of long-term energy adequacy concerns raised by NERC.[75] The PJM approach treats the question of flexibility needs to accommodate low-cost solar and wind generation as an economic matter to be addressed in operations, whereby operators evaluate the tradeoffs between combining flexible resources and low-cost wind and solar to meet demand, versus scheduling less flexible resources to help meet demand even if it means curtailing some low-cost wind and/or solar generation.
- Utilities conducting Integrated Resource Planning (IRP) now commonly include ELCC analysis to at least capture the energy adequacy value of wind and solar across all hours of the year. Such models commonly include many decades of weather data to identify correlations between hourly patterns of demand relative to wind output and solar output, thereby identifying potential periods of sustained low wind and solar output and the impact on energy adequacy. The IRP investment construct then reacts by procuring or retaining more readily dispatchable resources to fill in for those hours, thus ensuring energy adequacy.

For more information about existing mechanisms for maintaining long-term adequacy, and how they are leveraged under these adapted frameworks, see Appendix B.

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[71] CPUC Energy Division, 2021 Resource Adequacy Report, April 2023, pp. 22, 23; CAISO, Final Flexible Capacity Needs Assessment for 2023, May 17, 2022.

[72] CAISO, CPUC, CEC, Root Case Analysis: Mid-August 2020 Extreme Heat Wave, January 13, 2021, pp. 70-75.

[73] CAISO, Summer Market Performance Report, November 2, 2022, p. 13.

[74] PJM, Docket No. ER24-98, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023.

[75] NERC, 2021 Long-Term Reliability Assessment, December 2021.

B. Maintaining sufficient flexibility for operational energy adequacy

RELIABILITY NEED FOR INCREASED FLEXIBILITY

In its 2022 LTRA, NERC pointed to the rising value of flexibility for accommodating low-cost but variable wind and solar:

> *"In order to maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, some operators are seeing the need to have more system ramping capability. As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility. Maintaining ERSs [Essential Reliability Services, e.g. ramp capability] is critically important, and resources must be made available in the long-range resource portfolio as part of the planning process; market and other mechanisms need to be in place to deliver resources with ERS-capabilities to the operators."* [76]

In the 2021 LTRA, NERC stated that:

> *"In many areas, VERs [variable energy resources, e.g. wind and solar] are increasingly important to meet electricity demand. Operators must have flexible resources, including adequate dispatchable, fuel-assured, and weatherized generation, at their disposal. This is especially true in areas with high levels of variable generation to avoid shortfalls when VER output is insufficient to meet demand. [Footnote: Flexible resources refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads]."* [77]

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[76] NERC, 2022 Long-Term Reliability Assessment, December 2022, pp. 17-18.

[77] NERC, 2021 Long-Term Reliability Assessment, December 2021, p. 9.

The operational energy adequacy need amounts to the requirement to increase supply output fast enough to keep up with changing conditions.[78] Two distinct situations of change can be distinguished: (1) expected reductions in output of forecasted wind or solar; and (2) unexpected rapid reductions in output of wind or solar. These are different because the former can be addressed through optimal scheduling of existing flexibility capability (and, if necessary, securing additional installed flexibility capability), while the latter can only be addressed by maintaining the requisite flexibility in reserve, available at all times.

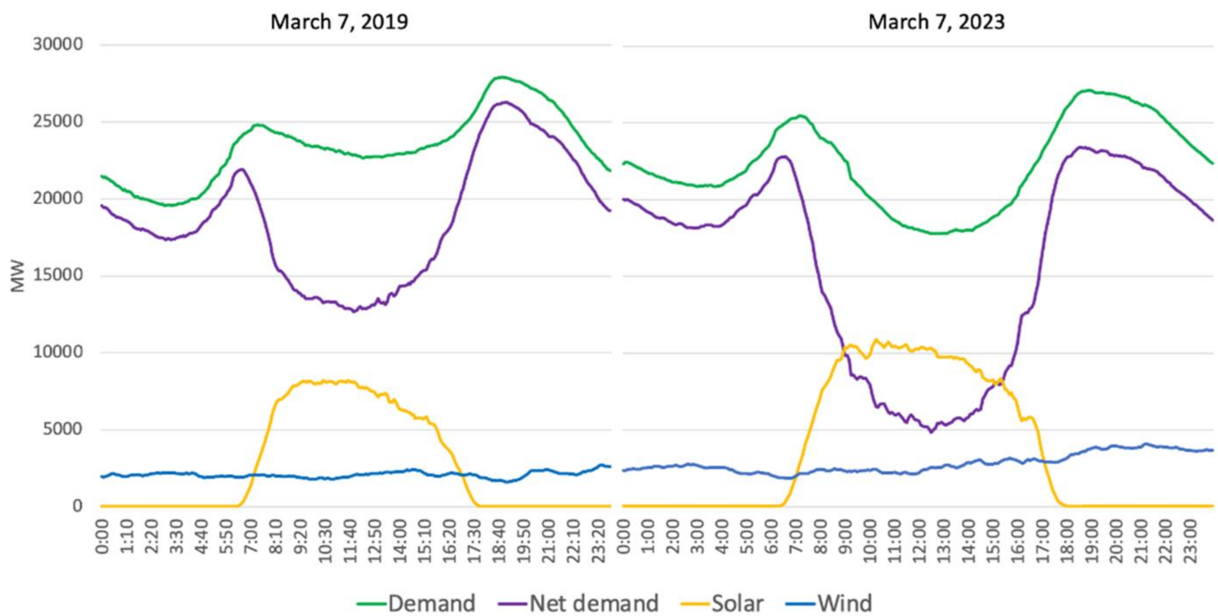
California's well known "duck-curve" provides an example of how expected patterns of renewable output are leading to increased needs for flexible resources. When solar output drops off as the sun sets, the reduction in output must be backfilled using flexible resources with the ability to increase output. In that sense, the flexible resources are deployed to meet total demand net of solar output, or "net demand."[79] High penetration of solar means that net demand is low during the day but displays a rapid increase around evening hours when solar output decreases, leading to a net demand shape similar to the silhouette of a duck, as shown in Figure 9 below.[80] This pattern in net demand is expected, and resource operators can plan their operations to ensure adequate flexible capacity to meet the sharp increase in daily net load around sunset. Flexibility to meet expected ramps can be considered an economic need, not a reliability one. If insufficient flexibility is available to accommodate the steep increase in expected net demand, then the flexibility that does exist is scheduled, and solar is scheduled for curtailment so that the net demand ramp is effectively less steep.

[78] The ability to rapidly decrease supply is also important for reliability, but is generally widely available.

[79] Note that net demand also accounts for wind generation but in this example, the duck curve shape is predominately caused by solar.

[80] CAISO, Fast Facts: What the duck curve tells us about managing a green grid, 2016.

FIGURE 9: NET LOAD IMPACT OF WIND AND SOLAR (CALIFORNIA)



Notes and Sources: Meredith Fowlie, California's Duck-Belly Blues, UC Berkeley Energy Institute Blog, March 13, 2023.

The 2018 "wind burn" event in the region operated by SPP provides a useful illustration for the need for flexibility due to unexpected changes in wind output. During their day-ahead scheduling process leading up to the event, SPP expected high wind generation and therefore scheduled fewer slow-start conventional generators to turn on. However, the day-ahead wind forecast was too high by over 7,000 MW (a significant number compared with SPP's 2018 summer peak demand of 50,000 MW).[81] As the day evolved, SPP called on ever more costly flexible units, narrowly averting emergency procedures.[82] As described in the report:

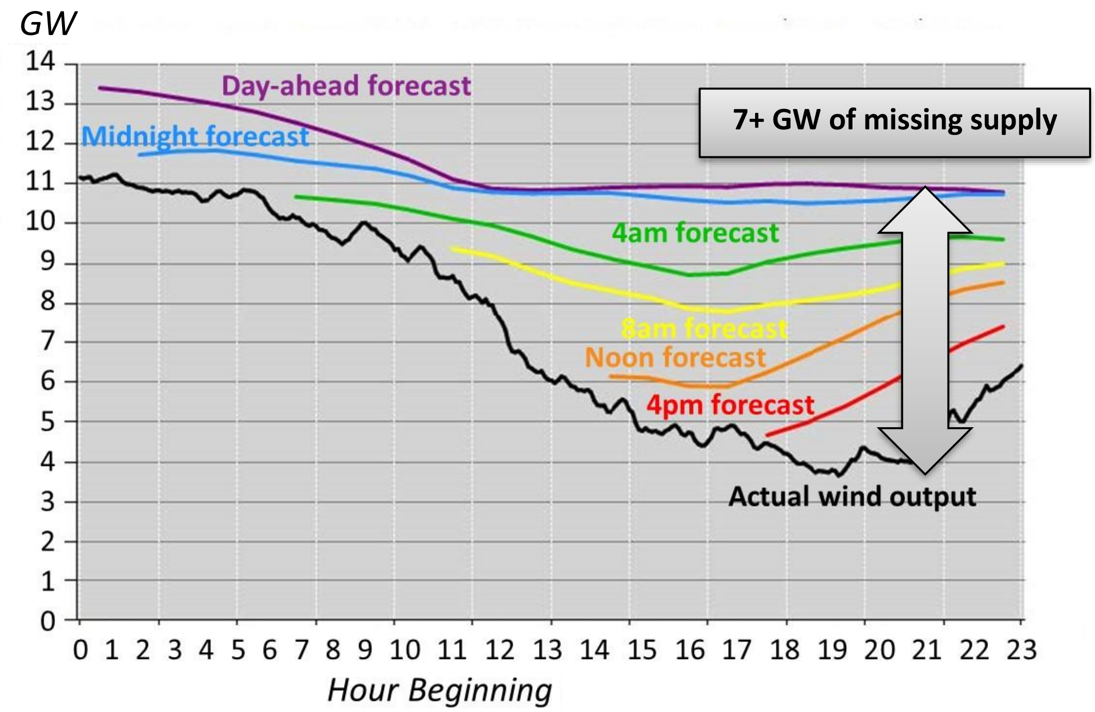
> *"As the studies got closer and closer to real-time, they gave more accurate predictions [of wind output], but were still very far off and continuously incorrectly predicted that there would only be a short dip before wind bounced back...Over 54 units were started for greater than 2,700 MW of out of market capacity (nameplate) by the time the event was concluded."*[83]

[81] SPP, Market Working Group Meeting, March 17, 2020, pp. 92; SPP, State of the Market Report: Summer 2018, October 15, 2018, p. 3.

[82] SPP, Market Working Group Meeting, March 17, 2020, pp. 92-98.

[83] SPP, Market Working Group Meeting, March 17, 2020, p. 95.

FIGURE 10: SPP FORECASTS OF WIND GENERATION ON DAY OF 2018 WIND BURN EVENT



Notes and Sources: Date of wind burn event was March 26, 2018. SPP, Market Working Group Meeting, March 17, 2020, Figure 24.

UNDERLYING TRENDS DRIVING INCREASING NEED FOR FLEXIBILITY

Growth in wind and solar is the trend driving increasing variability and uncertainty, which in turn leads to the rising need and value of flexibility to ensure operational energy adequacy. To the extent that coal plant retirements accelerate wind and solar deployment as replacement resources, such retirements indirectly increase this need.

GAPS IN USING AND PROCURING FLEXIBILITY

Customers benefit when the grid can accommodate all wind and solar output, because the underlying energy source is essentially free once the plants are built. However, since wind and solar output is both variable and uncertain, flexibility in the resource fleet is required to perform such accommodations. At lower deployment levels, this can be achieved with the same flexibility that has long been used to manage similar variability and uncertainty in demand. That is, through day-ahead generator scheduling, monitoring and arranging dispatchable upward capability as needed to meet increasing tightness, and reserving some flexible supply to deal with contingencies. However, at higher deployment levels, the magnitude of flexibility needed to take full advantage of the wind and solar could exceed the capability of the existing flexible resources (at least as utilized in the status quo system). At that point, either the wind and solar can be curtailed to reduce the variability (thus losing the benefit of some zero-cost supply), or additional steps can be taken to further optimize existing flexibility or secure additional flexibility.

To evaluate whether existing flexibility capabilities and mechanisms are sufficient to meet the need, grid operators sometimes perform ad hoc studies, and in other cases regular assessments.[84] [A] These have led to a variety of reforms to utilize and procure flexibility (as described immediately below), as well as direct long-term procurements of flexible capacity.[85]

In some cases, lack of flexibility has manifested in operations. In cases of especially large <u>expected</u> variability in renewable supply, insufficient flexibility capability had lead to curtailment of wind and solar that is deemed excessive and undesirable.[86] In cases of large unexpected variability in renewable supply, insufficient flexibility can lead to reliability problems and emergencies (e.g. the SPP wind burn example above).

Many grid operators lack a formal process to evaluate long-term flexibility needs, relying on spot energy and reserve market prices to incentivize needed flexible capacity to enter the market. Absent such a mechanism, grid operators risk needs for flexibility growing faster than the pace that flexible products (which align price signals with flexibility value) can be designed and new capacity can be installed. In any case, as the value of flexibility rises, reforms to day-ahead

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[84] Several of these assessments also include considerations of long-term adequacy planning and operating reliability. See PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022; General Electric Energy Consulting, PJM Renewable Integration Study, March 31, 2014; PJM, PJM's Evolving Resource Mix and System Reliability, March 30, 2017; MISO, 2022 Regional Resource Assessment, November, 2022; MISO, Renewable Integration Impact Assessment (RIIA), February 2021; ERCOT, Impact of Growth in Wind and Solar on Net Load, October 25, 2021; ISO-NE, 2021 Economic Study: Future Grid Reliability Study Phase 1, July 29, 2022; Analysis Group, Pathways Study: Evaluation of Pathways to a Future Grid, April 2022; NYISO, Comprehensive Reliability Plan, November 17, 2021; CAISO, Final Flexible Capacity Needs Assessment for 2023, May 17, 2022, p. 1.

See also Row [A] of Table 3 for additional examples of inverter-based resource integration studies and transition efforts; CPUC, "Resource Adequacy Program," 2023, accessed December 13, 2023; CPUC, 2021 Resource Adequacy Report, April 2023.

[85] CPUC, "Resource Adequacy Program," 2023, accessed December 13, 2023; CPUC, 2021 Resource Adequacy Report, April 2023.

[86] For example, NREL states that while "*low levels of curtailment (e.g., less than 3%) may be a cost-effective source of flexibility, significant amounts of curtailment can degrade project revenues and contract values, impact investor confidence in renewable energy revenues, and make it more difficult to meet emissions targets*," CAISO and ERCOT (the only ISOs/RTOs that publicly report solar curtailment) have curtailed wind and solar at higher levels than the 3% threshold in recent years, while across all ISOs, wind power curtailment in 2022 averaged 5.3%, see Jaquelin Cochran, et al., Flexibility in 21st Century Power Systems, NREL, May 2014, p. 3; LBNL, Utility-Scale Solar 2023 Edition, October 2023, p. 40; DOE, Land-Based Wind Report, 2023, p. x.

scheduling and real-time dispatch systems to extract more flexibility from the existing fleet will become more attractive.

SOLUTIONS AND EXAMPLES

New and expanded operating reserves

To accommodate the full output of low-cost wind and solar resources, operators must be prepared with flexible resources held in reserve to respond to unexpected drop offs in output.[87] Such reserves are functionally similar to those used in traditional systems that also must cope with uncertainty in the form of unexpected changes in demand and sudden failures of large online generators. System operators have long maintained Operating Reserves, which consist of flexible generation and demand response resources that are available to quickly increase output or decrease demand in response to unexpected developments such as outages at generation units or transmission lines, or short-term changes in demand relative to forecast.[88] These Operating Reserves have long been used to manage variability in demand and cope with unpredictable generator output, and now are being increasingly used to handle the variability and uncertainty in wind and solar output. As more renewables have been integrated into the grid, grid operators have in some cases expanded the quantities of existing operating reserves secured (e.g., non-spinning reserve in ERCOT) or developed new types of reserves (such as ramp products in CAISO, SPP, and MISO, 30-minute reserves in MISO, proposed energy imbalance reserves in CAISO and day-ahead ancillary services initiative enhancements in ISO New England).[89]

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[87] Unexpected increases in wind and solar output present opportunities for more efficient scheduling but are generally not a reliability issue since transmission-connected wind and solar can be curtailed by the utility or grid operator in charge of balancing supply and demand in that region.

[88] NERC requires grid operators to maintain operating reserves to manage uncertainties while meeting the need to rapidly balance supply and demand. In its 2014 paper on Essential Reliability Services, NERC describes operating reserves as follows: "*ORs ensure a sufficient amount of resources are available to address load and generation imbalance. Some types of ORs include regulation, load following, and contingency reserves,*" and then describes each type as follows: "***Regulation****: Used to manage the minute-to-minute differences between load and resources and to correct for unintended fluctuations in generator output*"; "***Load Following****: Follow load and resource imbalance to track the intra- and inter-hour load fluctuations within a scheduled period*"; "***Contingency Reserves****: Resources that are slated to provide contingency reserve services are utilized during a contingency event, and contingency reserves ensure resources are available to replenish the amount of output used during the event, thus returning the system to the level of balance before the event.*" NERC, Essential reliability Services Task Force, October 2014, p. 3.

[89] Carrie Bivens, IMM Concerns with the AS Methodology and Recommended Improvements, September 22, 2023, p. 4; CAISO, "Flexible ramping product," 2023; CAISO, Revised Final Proposal – Day-Ahead Market

These new and expanded reserves play two roles: one is to make flexibility operationally available in real time in the requisite quantities. The other is to align the price for compensating such services with their value. This results in price signals that incentivize resources to invest in making flexibility available in real time (for example, by purchasing an option to buy gas in real time, or reserving energy stored in a battery despite profitable opportunities to discharge and sell energy now) and also contributes to incentives for long-term investments in new flexible capability, either through development of new resources or by enhancing the flexibility of existing resources. Prices are aligned with value through deliberate development of demand curves for the reserves, reflecting their ability to improve reliability and therefore avoid rotating outages.[90]

Well-designed pricing can facilitate the rapid development of flexible resources, increasing installed flexibility while deploying it optimally and paying prices that appropriate reflect trade-offs associated with not having the flexibility. For example, driven largely by ancillary services pricing, battery capacity has increased from 0 GW in ERCOT in 2018 to 3 GW as of October 2023.[91]

Enhancements to day-ahead and other forward resource scheduling

With more battery storage, system operators are revisiting the question of whether such resources will provide optimal reliability value through a decentralized model in which resources submit simple offers to sell energy and respond to price signals, or instead via a centralized daily schedule optimizer that chooses the optimal hours of operation given the resources' constraints (including economic factors). U.S. ISOs/RTOs generally favor the latter approach for conventional generation, simulating the particular operating limitations of these in their daily scheduling systems (e.g., accounting for start-up time, minimum run time, and ramp rate limits). However, such systems today generally do not optimize around the operating limitations of battery storage systems (except for pumped hydropower storage in some regions). CAISO has stood out in making such a reform, enhancing its day-ahead resource scheduling process to optimize battery

Enhancements, May 1, 2023, p. 5; FERC, Docket No. ER20-1617-000, July 16, 2020, Order Accepting Tariff Revisions; MISO, "Business Practice Manual 002," September, 30, 2022, pp. 52-55; ISO-NE, "Day-Ahead Ancillary Services Initiative Key Project," 2023, accessed December 13, 2023.

90 These demand curves are based on the probability of rotating outages as well as estimates of the value of load interrupted during such outages, often referred to as the Value of Lost Load (VOLL). For an example of a VOLL-backed demand curve for reserves, see ERCOT, 2022 Biennial ERCOT Report on the Operating Reserve Demand Curve, October 31, 2022. For more details on reserve demand curve development, see PJM, Operating Reserve Demand Curves (ORDC) for Reserve Price Formation Project, June 9, 2021, pp. 10-12.

91 EIA, Preliminary Monthly Electric Generator Inventory, November 22, 2023.

schedules across the day with the intent of maximizing their reliability value (including flexibility value).[92] Such enhancements are also under consideration at other ISOs/RTOs.[93]

Other enhancements to day-ahead market processes have been discussed to better align prices with flexibility value in order to efficiently incentivize investments in flexibility.[94] Grid operators have explored and sometimes implemented other enhancements (not always implemented), such as more granular intervals and longer look-ahead periods.[95] Grid operators have also discussed introducing more or better intraday scheduling processes, effectively waiting as long as possible to commit to schedules in order to take advantage of better forecast accuracy.

Enhancements to real-time dispatch and energy markets

Energy markets at ISOs/RTOs were originally settled on an hourly basis, even while prices were calculated every 5 minutes. Compensation was therefore based on hourly averaging of both output and prices, thus obscuring sudden and acute needs for energy within the hour (i.e., the need for quick flexibility). The result was to dampen the incentive for flexible resources.[96] FERC required all ISOs/RTOs under its jurisdiction to implement 5-minute energy settlements in 2016, thereby prompting a reform that increases revenue opportunities for flexible resources that can be available to quickly change output in response to rapid changes in system needs as reflected in changing prices.[97]

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92 CAISO, Special Report on Battery Storage, July 7, 2023, pp. 5-6

93 For example, ISO-NE may consider storage optimization in their day-ahead market enhancement project, see ISO-NE, ISO New England's Draft 2024 Annual Work Plan (AWP), September 21, 2023.

94 William Hogan, Electricity Market Design: Multi-Interval Pricing Models, Harvard Electricity Policy Group, June 22, 2020.

95 For example, see CAISO proposal for fifteen-minute granularity in the day-ahead market, ISO-NE discussion of multi day-ahead energy and reserve market, and Southwest Power Pool market design proposal of a multi-day market; CAISO, Day-Ahead Market Enhancements Phase 1: Fifteen-Minute Granularity, February 28, 2019, CAISO, "Day-Ahead Market Enhancements Archive," 2019, accessed December 14, 2023; Kathleen Spees, et al., Market-Based Mechanisms for Winter Energy Security in NE, The Brattle Group, December 2018; SPP, SIR18 HITT R3C Multi-Day Market: Market Design, March 18, 2020.

96 Australian Energy Market Commission, Five-Minute Settlement Rule Final Determination, November 28, 2017.

97 FERC, 155 FERC ¶ 61,276, June 16, 2016, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators.

Other enhancements to real-time dispatch and pricing procedures have also been discussed, aimed at producing appropriate incentives for flexibility and optimizing the flexibility of existing capabilities.[98]

For more information about how existing mechanisms for meeting short-term adequacy needs work, and how they have been adapted to meet the rising value of flexibility, see Appendix B.

C. Maintaining Essential Reliability Services with many inverter-based resources

THE INDUSTRY NEED FOR ESSENTIAL RELIABILITY SERVICES

Generators have long played an important role in stabilizing the grid so that it can sustain sudden disturbances (such as lightning strikes or short circuits) and quickly return to normal operations. They accomplish this by providing nearly all of the Essential Reliability Services (described below, for example inertial response) that secure operating reliability. As system operators rely more on inverter-based renewable generators and batteries (types of generators for the purposes of this discussion) to meet demand, they must increasingly utilize the capabilities of these resources to contribute to stability during and after such events, thereby replacing the Essential Reliability Services of the conventional generators that they displace. According to NERC President and CEO James Robb:

> *"We must identify and integrate new resources to replace retiring generation that provides both sufficient energy and essential reliability services needed for stable grid operations."*[99]

For example, consider the inertial response that conventional generators naturally provide (explained in more detail below). This response traditionally comes from the physical attribute of inertia associated with the spinning mass of conventional turbines, and acts to stabilize

98 Erik Ela and Mark O'Malley, Scheduling and Pricing for Expected Ramp Capability in Real-Time Power Markets, Institute of Electrical and Electronics Engineers, 2015; ISO-NE, Procurement and Pricing of Ramping Capability, December 13, 2017.

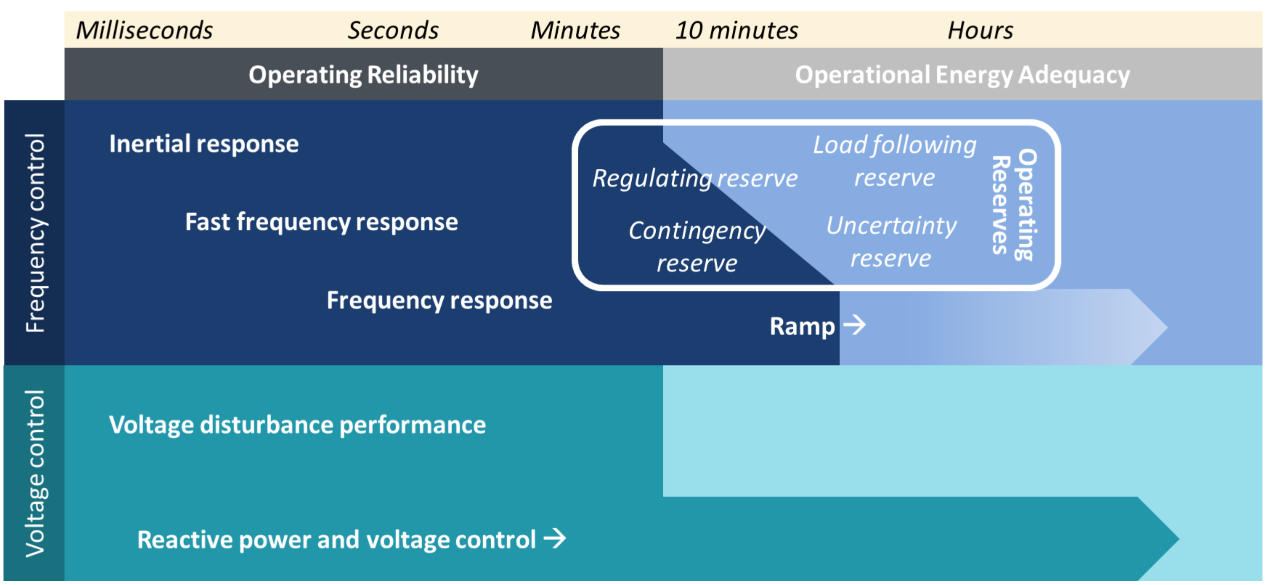
99 U.S. Senate Committee on Energy and Natural Resources, Full Committee Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts, June 1, 2023; James B. Robb, Testimony of James B. Robb, U.S. Senate Committee on Energy and Natural Resources, June 1, 2023.

frequency immediately following the loss of a large generator. In a future with no conventional generators online, inverter-based resources (including batteries) will need to be programmed to replace this inertial response with a similar functionality, to immediately increase output following the loss of a generator and thereby stabilize frequency. Battery and other technologies currently provide this service in other parts of the world and, when the need arises, U.S. grid operators will need to define and procure this service and the technology will need to be enabled.

To the extent new resource types are unable to replace these Essential Reliability Services for whatever reason, they must be replaced through other means, such as through dedicated devices such as synchronous condensers (which provide similar operating reliability services as conventional generators).

By leveraging the Essential Reliability Services capabilities of inverter-based resources, monitoring the availability of such services and comparing it with the need, and procuring additional services when required, operators can ensure that the grid can sustain unavoidable disturbances and return to normal conditions quickly, thereby avoiding the risk of cascading blackouts across a wide area.

FIGURE 11: GRAPHICAL DEPICTION OF RELIABILITY ASPECTS AND TIMESCALES FOR THE ESSENTIAL RELIABILITY SERVICES



Notes and Source: Categories adapted from content in NERC Essential Reliability Services Task Force, Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014 and Electric Power Research Institute, Enhancing Energy System Reliability And Resiliency In A Net-Zero Economy, January 2022.

The Essential Reliability Services (as described by NERC) are as follows.[100]

Inertial response

Inertial response refers to the immediate change in power output that acts to resist an abrupt change in system frequency. Such a change in frequency follows a sudden change in the supply-demand balance, such as the failure of a large online generator. A rapid drop in supply immediately leads to declining system frequency (normally approximately 60 hertz) concurrent with a draw on inertial response to provide additional electrical power from all the conventional generations (and otherwise enabled resources) across the affected interconnection.[101] Inertial response is currently provided freely by online conventional generators (and to a lesser extent by synchronous motors). Since the three North American interconnections are large, and inertial response is added across all the sources within each, there is ample inertial response today. As the smallest of the interconnections, Texas has monitored system-wide inertial response since 2015 so that it can take steps to secure more if needed.[102]

Frequency response

Frequency response (also known as primary frequency response or governor response) is another service for stabilizing frequency following a disturbance, acting a few seconds slower than inertial response. Like inertial response, it involves an autonomous increase in power output following a decline in frequency. Frequency response is required by FERC to be provided by all resource types, both conventional generators and inverter-based resources, while ERCOT procures frequency response as an ancillary service.[103] FERC requires frequency response capability in both the "upward" direction (providing more power when frequency dips) and the "downward" direction. Many resource types produce at their maximum capability much of the time, such as coal, nuclear,

[100] The Essential Reliability Services also include ancillary services that support operational energy adequacy. These are mentioned here, but discussed in more detail in Section IV.B on operational energy adequacy. The definitions here follow: NERC Essential Reliability Services Task Force, Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014.

[101] There are three large interconnections in the United States: the Eastern Interconnection, the Western Interconnection, and the Texas Interconnected system.

[102] ERCOT, ERCOT Interconnection Inertia Analysis; Paul Denholm, et al., Inertia and the Power Grid: A Guide Without the Spin, NREL, May 2020, p. v.

[103] FERC, F162 FERC ¶ 61,128, February 15, 2018, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response; FERC, Standard Large Generator Interconnection Agreement (LIGA), May 9, 2019, p. 44; ERCOT, Current Protocols – Nodal: Section 3: Management Activities for the ERCOT System, December 1, 2023, Section 3.17.2; Potomac Economics, 2022 State of the Market Report for the ERCOT Electricity Markets, May 2023, pp. 46-53.

wind, and solar generators. Some of these (such as many coal generators) can temporarily provide additional power to provide upward frequency response during such times, while others (nuclear, wind, many gas generators, and solar) cannot or will not.[104] During such times, those resources can (and must) provide downward frequency response. The physics of some smaller or more isolated grids may require an especially fast form of frequency response, in which case the faster service can be specified and procured as an ancillary service from more responsive resources.

Operating reserves

Operating reserves include ancillary services like contingency reserves, regulating reserves, load following reserves, and other emerging reserves. Subject to NERC requirements in many cases, these are all procured by grid operators through markets, or by utilities through self supply. In general, contingency reserve (which is designed to quickly replace the output from a generator loss) can be categorized as disturbance recovery (i.e., operating reliability), while the other operating reserves fall under operational energy adequacy, and so are covered in Section IV.B above.

Ramp capability

Dispatchable ramping capability (especially upward) over a minutes-to-hours timeframe is used to match demand and available supply in real time, especially when there are large and sustained swings in each, and especially under normal daily operating conditions. Ramp capability is currently secured through day-ahead and intraday scheduling processes and real-time dispatch, and to some extent operating reserves. Because wind and solar are generally very flexible in their downward ramp capability, upward ramp can be a more pressing need than downward. On-demand and sustained upward ramp is provided by flexible demand, medium- to long-duration storage, flexible fossil generation, hydropower generation, and wind and solar that has been curtailed for system balancing purposes (and can therefore be "uncurtailed"). Ramp capability supports operational energy adequacy and is therefore covered in detail in Section IV.B above.

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[104] Controls at conventional generators are also not always configured to realize their full Essential Reliability Services capabilities: *"While it has been determined that the Eastern Interconnection has generally sufficient frequency response as a whole, there are clues that point to issues with generator governor settings. The sponsors of this initiative believe that proper and consistent governor settings are the low hanging fruit to allay concerns raised by the Federal Energy Regulatory Commission (FERC) as to past trends in frequency response and the differing appearance of frequency in the East, compared to other Interconnections."* See NERC, Eastern Interconnection Frequency Initiative Whitepaper, October 28, 2013, p. 1.

Reactive power and voltage control (also known as steady-state voltage regulation)

Voltage control refers to the ability of dedicated devices, conventional generators, and inverter-based generators (including batteries and HVDC converter stations) to produce and consume something called "reactive power" in order to regulate the steady-state voltage of the grid within its nominal range on average and at all times. Although not always fully realized given the way they are configured, inverter-based resources generally feature equal or greater capability in this regard relative to conventional generators.[105] This is because: (1) inverter-based resources can be configured to be able to remain online at all times at low cost, providing ample voltage control capability; and (2) in some cases (such as for batteries and HVDC converter stations located close to their physical connection to grid that therefore have a low impedance path to the transmission system), the extent of their capability is inherently larger given the nature of the technology. FERC requires steady-state voltage regulation capability from both conventional generators (where it is sometimes called "automatic voltage regulation" or AVR) and inverter-based generators.[106] In some cases, the fixed and/or variable costs (including opportunity costs) of providing steady-state reactive power and voltage control are reimbursed as a cost-based ancillary service.

Voltage disturbance performance (also known as dynamic voltage support)

Voltage disturbance performance or dynamic voltage support contributes to voltage stability on very short timescales (i.e., "transient" timescales) during and after major sudden disturbances. It is the ability of generators and other devices to provide stabilizing current or a voltage source during and immediately after such events in order to minimize the immediate effect of the disturbance and quickly damp the subsequent system response to bring the system back to a normal state. In the continental U.S. today, this service is provided almost entirely by spinning

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105 *"Inverters should not have artificial settings imposed to limit reactive power output to the triangular boundary (other than the maximum power operating point, and other plant-level limits, or voltage limits at the terminals of the inverter)…If inverter-based resources were able to regulate voltage during any of these periods when their active power output was at zero (typically the inverter would be off-line), this control could significantly improve BPS voltage profiles, minimize voltage variability, and support voltage stability by providing dynamic reactive power during all operating modes… Figure 3.3 shows an inverter capability curve with near semi-circle capability."* In this context, a semi-circle is the highest reactive capability theoretically possible. See NERC, Inverter Based Resource Performance Guideline, September 2018, pp. 25-26, 36. Gabriel Benmouyal, The Impact of Synchronous Generators Excitation Supply on Protection and Relays, Schweitzer Engineering Laboratories Inc., October 2007, Figure 1.

106 FERC, 155 FERC ¶ 61,277, June 16, 2016, Reactive Power Requirements for Non-Synchronous Generation; FERC, Standard Large Generator Interconnection Agreement (LIGA), May 9, 2019, pp. 42-43.

machines, both conventional generators and dedicated non-generator devices called synchronous condensers. When properly configured, inverter-based resources (especially going forward) are capable of providing this service, albeit with distinctive dynamics relative to conventional machines (i.e. synchronous condensers and conventional generators).[107] Grid forming inverters are especially capable in this regard.[108]

UNDERLYING TRENDS DRIVING THE NEED TO REPLACE ESSENTIAL RELIABILITY SERVICES

Essential Reliability Services are required at all times, and by their nature cannot be provided by resources that are offline. Therefore, resources that are not retired but also rarely online only rarely provide Essential Reliability Services. Therefore, reforms described here to ensure adequate provision of such services must be pursued with rising inverter-based generation, regardless of whether coal generation remains in service or retires.

GAPS IN SECURING ESSENTIAL RELIABILITY SERVICES IN TOMORROW'S GRID

The capabilities of inverter-based resources are not currently fully realized in meeting the need for operating reliability. In the 2023 State of Reliability Overview, NERC found that "*newly built solar PV [photovoltaic] and battery storage resources continue to be commissioned with known performance issues; these issues have long been highlighted in disturbance reports and NERC alerts dating back to 2016*."[109]

NERC has identified many cases of inverters that erroneously tripped offline (i.e. disconnected from the grid) following a disturbance because they were poorly configured, lacked appropriate capabilities, or were inadequately commissioned.[110] Such performance presents a serious

[107] The voltage disturbance performance capability of inverter-based resources is different from that of conventional machines. This stands in contrast to the steady-state voltage control capability of inverter-based resources, which is similar to and arguably superior to that of conventional machines, as discussed in the "Reactive power and voltage control" section above.

[108] See Appendix B for discussion of grid-forming inverters.

[109] NERC, 2023 State of Reliability Overview, June 2023, p. 9.

[110] NERC, 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report, June 20, 2017, Southern California 8/16/2016 Event; NERC and WECC, 900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report, February 2018, Southern California Event: October 9, 2017; NERC, Panhandle Wind Disturbance, August 2022; NERC, 2022 Odessa Disturbance, December 2022; NERC, 2022 California Battery Energy Storage System Disturbances, September 2023, p. iv.; NERC, Inverter-Based Resource Performance Issues Report: Findings from the Level 2 Alert, November 2023. For more examples and details, see NERC, Quick Reference Guide: Inverter-Based Resource Activities, June 2023.

reliability concern, since it not only precludes any stability benefits from inverter-based resources, but risks exacerbating the effects of such disturbances.

NERC has identified the various causes of the erroneous tripping problems, and developed guidance accordingly:[111]

> *Disturbance analyses of BPS-connected solar PV tripping have identified a number of areas where the performance of inverter-based resources can be improved. In addition, reliability organizations around the world have devised grid code requirements to solve reliability issues with nonsynchronous resources. With this information, and working closely with the electric industry, NERC has captured a set of recommended performance specifications for inverter-based resources in this Reliability Guideline (guideline).*[112]

FERC and NERC are in the process of developing an enforcement regime to eliminate the erroneous tripping issue, as described in the "Solutions" section below.

A resource that is offline cannot provide Essential Reliability Services. We therefore distinguish the problem of erroneous tripping from the broader reliability interest in securing Essential Reliability Services from inverter-based resources, and discuss solutions to both below.

Essential Reliability Services provision from inverter-based resources is in various stages of technology maturity as well as varying levels of industry readiness with respect to managing deployment in the field and simulating dynamic responses with models. Today's inverters provide many Essential Reliability Services in practice, and indeed, under FERC regulations, they must be capable of providing two of them (voltage regulation and frequency response).[113] When coupled with modeling and tuning tools to integrate them into the grid, the latest inverter technologies can provide all the Essential Reliability Services, in some cases potentially exceeding the

[111] NERC identified these causes of erroneous tripping representing nearly all of the lost supply: inverter instantaneous AC overcurrent, passive anti-islanding (phase jump), inverter instantaneous AC overvoltage, inverter DC bus voltage unbalance, feeder underfrequency, incorrect ride-through configuration, plant controller interactions, momentary cessation, inverter overfrequency, PLL loss of synchronism, feeder AC overvoltage, and inverter under frequency. See NERC and Texas Reliability Entity, 2022 Odessa Disturbance, December 2022, p. 5.

[112] BPS stands for "Bulk Power System," effectively the regional grid. PV stands for "photovoltaic." See NERC, Reliability Guideline: BPS-Connected Inverter-Based Resource Performance, September 2018, pp. v, vii.

[113] From FERC Orders 827 and 842, inverter-based resources must provide primary frequency response and be capable of providing steady-state voltage regulation. See FERC, 155 FERC ¶ 61,277, June 16, 2016, Reactive Power Requirements for Non-Synchronous Generation Under; FERC, F162 FERC ¶ 61,128, February 15, 2018, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response.

capabilities of conventional generators. Therefore the gap in securing Essential Reliability Services is not generally technology capability. It may instead be due to either (1) a lack of coordination to require the necessary configuration or technology, which in turn requires new protocols involving multiple parties, for example in the case of realizing the full reactive capability of inverters for steady-state voltage regulation, described below, or (2) the fact that the service is not currently scarce and so has not been required or procured (such as inertial response).

SOLUTIONS TO REPLACE ESSENTIAL RELIABILITY SERVICES FROM OFFLINE OR RETIRED CONVENTIONAL GENERATORS

During times that inverter-based resources are available to produce low cost energy, fewer conventional generators are online. The Essential Reliability Services normally provided by the latter are therefore diminished, since conventional generators (unlike inverter-based generators) generally can only be online (and hence providing services) while also incurring large costs and producing a significant amount of power. These displaced services, and services from retired generators, must be replaced to maintain reliability.

Inverters are capable of providing all Essential Reliability Services to varying degrees. Battery-backed inverter-based resources in particular can, when programmed appropriately, provide certain services in greater quantity than comparably sized conventional generators.[114] Moreover, for several years, FERC has required inverter-based resources to provide two Essential Reliability Services.[115] As noted below, the most technologically advanced inverters (called "grid forming inverters") have recently been deployed in challenging transmission systems such as the grid in Australia, providing the most complex stabilizing Essential Reliability Service.[116]

The driver of potential shortfalls of Essential Reliability Services from inverter-based resources now is mainly due to the lack of processes to secure and configure these services, not a

[114] For example, inertia-like immediate frequency control and steady-state voltage regulation, when programmed correctly.

[115] Under FERC Orders 827 and 842, inverter-based resources must provide primary frequency response and be capable of providing steady-state voltage regulation.

[116] Referred to as "voltage disturbance performance" below. From NERC: *"GFM [grid forming] technology is commercially available and field-proven for transmission-connected applications, particularly for BESS (including standalone BESS7 in ac-coupled hybrid plants) as well as dc-coupled solar photovoltaic (PV)+BESS applications*." NERC, White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems, September 2023. For examples, see Bella Peacock, World's largest 'grid-forming' battery to begin construction in Australia, PV Magazine, August 10, 2021; and David Bissell, Hybrid Solar and Storage in Hawaii, T&D World, July 1, 2019.

technology limitation. Where such processes can only leverage some of the Essential Reliability Services from inverter technologies, or where the system cannot adapt to the different dynamic response of inverters, the remaining need can be met (generally at higher cost) with dedicated devices like synchronous condensers.[117]

Erroneous tripping of inverter-based resources precludes the provision of Essential Reliability Services, and exacerbates the reliability impact of disturbances. Regulators are introducing processes designed to solve this problem. Many grid operators are proposing to require conformance with IEEE standard 2800, which would expressly prohibit the various controller actions that lead to such tripping. Accompanying the new standard are testing protocols to ensure specific inverter models and generation facilities comply with the standard.[118] Meanwhile, FERC has issued Order 901, which requires NERC to issue new Reliability Standards establishing protocols to stop such tripping from occurring, thereby unlocking its enforcement powers to ensure the new protocols are followed.[119]

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[117] As NERC States: *"The bulk power system (BPS) in North America continues to experience a change in generating resources, technologies, and transmission system devices used to provide essential reliability services (ERS) such as voltage control, frequency control, and ramping/balancing capability. In particular, the BPS is experiencing a rapid change in generation resource mix, with an increasing installation base of inverter-based generation resources and accompanying retirements of synchronous generation resources. Additionally, generation is increasingly being located farther from load centers than it was in the past. These factors are contributing to an increased reliance on non-generation transmission-connected dynamic reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based – to provide ERS in the BPS. Synchronous condensers are being used to provide dynamic reactive power and transient voltage support, as well as synchronous inertia and fault current contribution in weak grid conditions. Static var compensators (SVCs) and static compensators (STATCOMs) are increasingly being used to provide dynamic reactive power and transient voltage support."* NERC, Transmission Connected Dynamic Reactive Resources and HVDC Equipment – Assessment of Applicability in Reliability Standards. NERC SAMS White Paper, February 2019.

[118] IEEE, Standard 2800-2022, April 22, 2022. ISO-NE, MISO, and NYISO are among the grid operators proposing to require conformance with IEEE standard 2800. See Brad Marszalkowski, PP5-6 Updates: Updates for the Clean Energy Transition, Adoption of IEEE 2800 and Improvements to Modeling of Inverter-Based Resources, ISO-NE, September 19, 2023; MISO, Inverter-Based Resource performance Requirements, Interconnection Process Working Group, March 14, 2023; Keith Burrell, Overview of Industry Activities Related to Inverter-Based Resources and IEEE 2800, NYISO, February 8, 2023.

[119] NERC will reform its performance requirements for inverter-based resources and consider commissioning requirements to confirm that new such resources are configured properly. NERC will also "*develop two Reliability Standard Projects…to produce performance and post-disturbance analytical expectations that will address the systemic IBR performance issues and support a more reliable IBR fleet."* See NERC, Inverter-Based Resource Performance Issues Report, November 2023, Findings from the Level 2 Alert, p. v.

FERC issued Order No. 901 in October 2023, which, among other things, requires NERC to establish reliability standards that prohibit the misoperation of new and existing inverter-based resources as observed in recent NERC reports. FERC also issued Order 2023 in July 2023 mainly to require reforms to the interconnection process at the ISOs/RTOs. However, the order also includes revisions to new interconnection agreements that require inverter-based resources to better contribute to stabilizing the grid during disturbances. See FERC, 185 FERC ¶

Inverter-based resources that do not erroneously trip following major disturbances can provide Essential Reliability Services to mitigate the impact of those disturbances and aid in recovery. Having defined the Essential Reliability Services, grid operators must monitor their potential shortfall where necessary and, when the risk of shortfall emerges, establish processes for securing them (from inverter-based resources or otherwise), potentially following the existing model for defining and procuring the subset of Essential Reliability Services that are currently ancillary services (i.e., operating reserves), or through transmission planning processes.

To that end, the following describes: (1) the capabilities of inverter-based resources to provide each Essential Reliability Service in the operating reliability domain; (2) potential alternative sources of such services; and (3) reforms grid operators can or must take to ensure adequate Essential Reliability Services in the future as inverter-based resources take on an increasing role in operations.

Inertial response

When inertial response becomes scarce in the future with few or no conventional generators online across an entire interconnection, reforms will be needed to ensure that frequency is stable on the fastest timescales. Such reforms can either procure inertial response service as an ancillary service (broadly analogous to other operating reserves), as is currently done in the Wholesale Electricity Market i(WEM) n Australia, or it can be mandated as an operational requirement, similar to wind turbines in Quebec, Canada since 2011.[120] Note that batteries are increasingly set

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61,042, October 19, 2023, Reliability Standards to Address Inverter-Based Resources and FERC, 184 FERC ¶ 61,054, July 28, 2023, Improvements to Generator Interconnection Procedures and Agreements.

[120] Only spinning generators feature literal physical inertia. This physical inertia in turn produces a power response to sudden changes in supply-demand balance which underlies the needed Essential Reliability Service. Inverter-based resources provide the same Essential Reliability Service function by measuring frequency and delivering a near-instantaneous power response when it changes abruptly. This is sometimes called "synthetic inertia." For Quebec wind turbine requirements see Peter Fairley, Can Synthetic Inertia from Wind Power Stabilize Grids?, IEEE, November 7, 2016.

From the Australian Energy Market Operator (AEMO): "*Rate of Change of Frequency Control Service (RoCoF Control Service) is the service, measured in MWs, of providing Inertia which provides an instantaneous response to slow down the rate of change of the SWIS [South West Interconnected System] Frequency." AEMO defines inertia as "The kinetic energy (at nominal frequency) that is extracted from the rotating mass of a machine coupled to the power system to compensate an imbalance in the system frequency. Alternatively, the 'synthetic inertia' provided by nonrotating machines which can be programmed to provide inertia to the system. An example is inverter-based technology."* See Australian Energy Market Operator (AEMO), "Summary of Frequency Co-optimised Essential System Services," 2022, accessed December 12, 2023 and AEMO, Registration Technical Data Guide [in the WEM], Version 4.1, July 2023.

up to provide inertial response service.[121] Batteries that are online but not producing power can provide their full nameplate capacity in this service, in which case they can provide more than a comparably-sized conventional generator. Alternately, inertial response can be provided by dedicated devices such as synchronous condensers.[122] Because the interconnections in the United States are large with many resources, and the inertial response of each resource therein is added across each interconnection, such reforms are unlikely to be needed for many years, with the possible exception of Texas.

Frequency response

Similar to other generation types such as gas and nuclear, when wind, solar, and batteries are operating at their maximum capability, they generally cannot provide upward frequency response (and therefore they provide only downward frequency response during such times).[123] However, at other times, such resources would be expected to have ample upward frequency response capability. For example, most of the 14,000 MW of utility-scale batteries currently installed in the U.S. spend many hours a day online, not at maximum output, and therefore are available with ample upward frequency response capability.[124] In the future, wind and solar generation output may be curtailed in an increasing number of hours to maintain system-wide

Similarly: "*The need for a formalised RoCoF Control Service has not been required in the past since most of the generation fleet consisted of large coal and gas units that had provided significant inertia (stabilized system frequency) through normal operations. With the expected retirement of many of these units over the next decade, synthetic inertia will need to be provided by batteries and intermittent plant (e.g., wind)*." See Marsden Jacob Associates, Revenue Adequacy for Generators in the WEM; Prepared for Australian Energy Council, April 1, 2022.

[121] For example, see the Hornsdale Power Reserve in South Australia, which began providing inertia services in 2022; See Hornsdale Power Reserve, "Overview," 2022, accessed December 17, 2023; Bella Peacock, Hornsdale Big Battery begins Providing Inertia Grid Services at Scale in World First, PV Magazine, July 27, 2022. See also the Victorian Big Battery in Victoria, Australia which is currently participating in a grid inertia measurement trial; Andy Colthorpe, Grid Inertia Measurement Trial at Australia's Biggest Battery Storage Project, Energy Storage News, April 25, 2023.

[122] From NERC: *"Synchronous condensers are being used to provide dynamic reactive power and transient voltage support, as well as synchronous inertia and fault current contribution in weak grid conditions*." NERC, Transmission Connected Dynamic Reactive Resources and HVDC Equipment – Assessment of Applicability in Reliability Standards. NERC SAMS White Paper, 2019.

[123] Controls at conventional generators are also not always configured to realize their full frequency response capabilities. See NERC, Eastern Interconnection Frequency Initiative Whitepaper, October 28, 2013, p. 1: *"While it has been determined that the Eastern Interconnection has generally sufficient frequency response as a whole, there are clues that point to issues with generator governor settings. The sponsors of this initiative believe that proper and consistent governor settings are the low hanging fruit to allay concerns raised by the Federal Energy Regulatory Commission (FERC) as to past trends in frequency response and the differing appearance of frequency in the East, compared to other Interconnections."*

[124] CAISO, Special Report on Battery Storage, July 7, 2023, Figure 2.6.1.

power balance. During such times, those resources are capable and required to provide upward frequency response.

ERCOT already procures adequate frequency response as an ancillary service, so fundamental reform may not be needed there (especially if inertia levels are maintained). Outside ERCOT, while FERC already requires frequency response from all resource types, upward frequency response could nonetheless become scarce in some periods. In that case, reforms would be needed to procure frequency response as a new ancillary service, following the model of ERCOT and many other global jurisdictions, or it can be procured on long term contracts, as CAISO has done.[125]

Operating reserves

Operating reserves are currently procured as ancillary services in wholesale markets, or self-supplied by utilities under NERC requirements. Inverter-based resources (especially batteries) as well as other emerging resource types (such as flexible loads) are capable of providing them already, with many examples of such provision.[126] The remaining reforms therefore consist of: (1) adapting the operating reserves to suit the changing needs of operational energy adequacy (discussed in Section IV.B above); and (2) ensuring there are no artificial barriers to provision of these reserves from new resource types. With batteries providing significant shares of certain ancillary services in CAISO, ERCOT, and PJM, and with a FERC order several years ago mandating removal of such barriers, much work has already been done towards the latter reform.[127] However, some grid operators categorically exclude wind and solar from providing certain Operating Reserves, even when they are capable of doing so (for example, because they have upward ramp capability during times that they are curtailed for system balance).[128]

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125 ERCOT, Ancillary Services in ERCOT: Participation by Energy Storage Resources, August 21, 2019; Anna Collyer, National Electricity Amendment (Fast frequency response market ancillary service) Rule 2021 No.8, Australian Energy Market Commission, July 15, 2021; Alberta Electric System Operator (AESO), Ancillary Services, 2016, accessed December 13, 2023; FERC, 158 FERC ¶ 61,129, February 2, 2017, Order on Compliance, Clarification, and Rehearing.

126 CAISO, Special Report on Battery Storage, July 7, 2023, pp. 5-6; Xin Fang, et al., Providing Ancillary Services with Photovoltaic Generation in Multi-Timescale Grid Operation, NREL, April 2021; Craig Glazer and Scott Baker, Re: Energy Conservation Program: Notice of Proposed Rulemaking for Energy Conservation Standards for Residential Water Heaters, April 19, 2013, Docket Number: EERE–2012–BT–STD–0022, RIN Number: 1904–AC78.

127 FERC, F162 FERC ¶ 61,128, February 15, 2018, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response.

128 MISO, Dispatchable Intermittent Resources vis-à-vis Ramp Capability Products, Docket No. ER23-1195-000, filed February 28, 2023: *"[MISO proposes] to consider Dispatchable Intermittent Resources (DIRs) ineligible to provide Up Ramp Capability and Down Ramp Capability…."*

Ramp

Ramp is the ability of resources to readily change their output to help balance supply and demand in a grid area, especially during ordinary daily operations. The flexibility capabilities of resources that provide ramp service are discussed in Section IV.B above.

Reactive power and voltage control

Since all inverter-based resources are already capable of and required to provide this service, fundamental reforms are not necessary. However, NERC identified in 2018 a variety of opportunities to better take advantage of the capabilities of inverters to provide this service, such as maximizing the extent of voltage regulation that should be enabled, clarifying the details of the voltage regulation control mode, and considering use of 24×7 voltage control capability where optimal.[129] These opportunities have yet to be fully realized, as evidenced by a recent NERC survey.[130]

Voltage disturbance performance

Today's inverter-based resources provide lower (or zero) dynamic voltage support to stabilize voltage in the milliseconds-to-seconds timescale during and following a large disturbance, such as a short circuit, with some emerging exceptions.[131] The IEEE standard 2800, published in 2022, standardizes the stabilizing voltage response of inverter-based resources during and after such disturbances, and with its growing adoption, inverter-based resources will serve as more effective sources of dynamic voltage support.[132] However, mainstream inverter control

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Debra Lew (ESIG) and Drake Bartlett (Xcel Energy), et al., Secrets of Successful Integration—Operating Experience With High Levels of Variable, Inverter-Based Generation, IEEE Power & Energy Magazine, November 2019. "*The company [Colorado utility Xcel Energy] has also determined the volume of curtailed VER generation that can dependably provide up regulation and 10-min spinning reserves. This enables the use of curtailed VER generation to provide some of the spinning reserve requirements. In this way, some reliability concerns associated with the inherent variability of very high VER penetrations are addressed by the VERs providing essential reliability services.*"

[129] NERC, Reliability Guideline: Natural Gas and Electrical Operational Coordination Considerations, March 22, 2023, pp. 28-31, 34-38.

[130] NERC, Inverter-Based Resource Performance Issues Report: Findings from the Level 2 Alert, November 2022, p. 7 makes clear that, in many cases, much of the reactive capability of inverter-based resources has been disabled due to plant configurations.

[131] During less extreme disturbances, inverters provide supporting current during a disturbance, albeit in lower quantity relative to a synchronous machine. Some inverters enter a mode called "momentary cessation" during certain low-voltage conditions, in which case they are not supporting the grid at all during the disturbance.

[132] IEEE, Standard 2800-2022, April 22, 2022. MISO is preparing to require compliance with parts of IEEE 2800 starting in 2024. See MISO, MISO update on IEEE2800 adoption efforts, November 10, 2023. New York State Reliability Council has proposed to require them starting in 2024. See New York State Reliability Council (NYSRC),

technology still depends on being electrically close to a synchronous machine that can provide a reference voltage to follow (these are called "grid following" inverters). With very high deployment of inverters across a wide area, barring further transmission connection to other areas with synchronous machines, existing inverter technology can create a "weak grid" condition. To support operating reliability, such conditions must be strengthened either through deployment of an emerging technology known as "grid forming" inverters or through investment in synchronous condensers, which are higher cost but more traditional alternatives that may more easily comport with other legacy aspects of the grid. Grid forming inverters are discussed in more detail in Appendix B.

The challenging voltage-related Essential Reliability Services described above are required because of the physics of AC grids, which in some cases can be difficult to operate stably, even with conventional generators (especially when transferring large amounts of power over long distances). Therefore, an important strategy for reducing the need for local Essential Reliability Services in such conditions is to consider instead transferring power with high-voltage DC transmission, which does not suffer from such instability tendencies, and indeed can serve to stabilize the AC grid it interfaces with (when equipped with so-called Voltage Source Converter technology).[133]

The reforms described above have been discussed among grid operators and power systems engineers for some time. They regularly perform ad hoc studies to establish whether the Essential Reliability Services must be monitored in order to inform the pace of reform.[134] In case the need for new sources of the short-duration Essential Reliability Services that are the focus of operating reliability (i.e., inertial response, steady-state voltage regulation, and dynamic voltage support) outpaces the speed of reform to procure them, investment in synchronous condensers can constitute a backstop solution that is deployable (albeit at some cost) within a year or two.[135] These dedicated devices have much the same physical design and characteristics as conventional

"Reliability Rule Revisions," accessed December 13, 2023. ISO-NE is proposing to require IEEE 2800 in three phases. See Brad Marszalkowski, PP5-6 Updates, ISO-NE, September 19, 2023, Updates for the Clean Energy Transition, Adoption of IEEE 2800 and Improvements to Modeling of Inverter Based Resources.

133 Johannes Pfeifenberger, et al., The Operational and Market Benefits of HVDC to System Operators, The Brattle Group, September 2023, p. 1.

134 See row [A] of Table 3 for examples of ad hoc studies.

135 For example, see an ERCOT 2023 report on synchronous condensers proposed to maintain system reliability given for projected growth in wind and solar capacity by 2025; ERCOT, ERCOT Assessment of Synchronous Condensers to Strengthen the West Texas System, June 27, 2023.

generators, only without the sustained production of energy, and they therefore have a similar capability to provide these Essential Reliability Services.

D. Reliable integration of gas generation

THE NEED FOR ENERGY DURING EXTREME COLD EVENTS AND UNDERLYING TRENDS

The increased reliance on natural gas to meet electricity demand has increased the supply of flexible resources on the system, but has also highlighted fuel availability risk and increased the need for enhanced coordination practices between the gas and electric industries.[136]

NERC has said:

> *"The electricity sector's growing reliance on natural gas raises concerns from Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), market participants, industrial electricity and gas consumers, national and regional regulatory bodies, and other government officials regarding the ability to maintain electric system reliability when the capacity to deliver natural gas supplies to power generators is constrained. The extent of these concerns vary from region to region; however, they are most acute in areas where power generators rely on interruptible gas pipeline transportation and where the growth in gas use for power generation is growing the fastest."*[137]

As observed during the 2013/14 Polar Vortex in PJM, the 2021 Winter Storm Uri in Texas, and the 2022 Winter Storm Elliott in most of the East, South, and the Midwest, many gas-fired generators that operators were relying on to meet adequacy needs were unable to operate due to gas supply problems and equipment malfunctions during extreme cold weather, causing extreme grid stress and historic rotating outages in some regions.[138] During Winter Storm Uri in 2021, the supply of natural gas and generation of electricity were "inextricably linked," with one

[136] FERC, Technical Conferences: 2023 Annual Reliability Technical Conference, December 11, 2023.

[137] NERC, 2013 Special Reliability Assessment: Accommodating an Increasing Dependence on Natural Gas for Electric Power, May 2013.

[138] NERC, Polar Vortex Review, September 2014; FERC, NERC, Regional Entities, The February 2021 Cold Weather Outages in Texas and the South Central United States, November 2021; PJM, Winter Storm Elliott Event Analysis and Recommendation Report, July 17, 2023; Energy Ventures Analysis, Operation of the U.S. Power Generation Fleet During Winter Storm Elliott, February 2023.

major issue being the lack of firm gas supply contracts held by generating units. Only 29 percent of natural gas-fired generating units had firm contracts for both purchase and delivery of gas during the event.[139] During Winter Storm Elliott, nearly 1.5 million people in Eastern, Southern and Midwestern parts of the U.S. lost access to power, as unexpected outages at power plants left grid operators with insufficient supply to support demand. A PJM report found that gas-fired generation accounted for nearly 70% of these unplanned outages.[140] Failure to start, freezing of crucial equipment, and insufficient gas availability were identified as key reasons for the outages. The event highlighted the reliability risks of a system supported increasingly by natural gas.[141]

GAPS IN UTILIZING AND ACCURATELY ASSESSING RELIABILITY VALUE OF GAS GENERATION

Reliability concerns related to increased gas generation stem in part from the lack of coordination and operational flexibility between the electricity and natural gas markets. The National Petroleum Council in a 2019 study emphasizes the importance of "*the need to improve interoperability between the natural gas and electricity wholesale markets as critical to improving reliability and resiliency, and to foster infrastructure deployment.*"[142] The lack of coordination between markets and generators' inability to access sufficient gas supply has resulted in serious reliability implications.

Failure to procure adequate fuel supplies is a major reliability concern of system operators. Generally, differences in scheduling timelines in market operations between natural gas markets and electricity markets creates an uncertainty for gas-fired generation owners to respond timely to unexpected changes in electric market conditions. Specifically, coordination between these markets has been difficult because of different operational flexibility, such as the difference in operational day between the two markets, limited incremental availability of gas to adjust to quickly changing needs, and scheduling that extends multiple days ahead over weekends.[143]

[139] FERC-NERC-Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, November 2021, pp. 206.

[140] PJM, Winter Storm Elliott: Event Analysis and Recommendation Report, July 17, 2023.

[141] *Ibid.*

[142] National Petroleum Council (NPC), Gas/Electric Coordination and Natural Gas Pipeline Deployment, December 12, 2019.

[143] Dominion Energy, Natural Gas and Electric Market Coordination, November 5, 2021, pp. 10-12.

Another reliability concern has been insufficient winterization across the generation fleet, particularly for gas plants, as well as for fuel delivery systems. During Winter Storm Uri, forced generation outages were due to a combination of generator failures (i.e. power plant instrumentation and freezing, wind turbine blade freezing, and power plant equipment failure), power line freezing, as well as fuel availability issues (natural gas production and transport outages due to freeze-related issues, and coal/oil fuel unavailability) with the majority of outages caused by gas fuel availability issues.[144] Winterization can include insulating, warming, and/or enclosing power plant instrumentation components and lines within buildings, improving minimum operating temperatures of plants, wind turbine blade de-icing methods, and snow removal for solar panels. For gas fuel supply it can include requiring plants to have firm transportation, dual fuel capabilities, or on-site storage. NERC has recently issued cold weather standards that have been accepted by FERC however revised standards are forthcoming based on FERC's comments.[145]

Even with issues with winterization and fuel supply, gas generation provides significant adequacy value. However, today's long-term adequacy values fail to accurately quantify that value, focusing solely on the summer rated capacity of the unit or, in some cases, on the summer rating adjusted downward for the rate of random forced outages. The latter approach is superior to the former, however, it overestimates the reliability value of generators that systematically fail across the fleet at the same time that demand is at unusually high levels. Such correlated outages, which are in part driven by extreme temperatures, can be captured in the ELCC models, as described in Section IV.A above.[146]

SOLUTIONS AND EXAMPLES TO IMPROVE RELIABLE INTEGRATION OF GAS GENERATION

Reliability planning in many regions (especially in the Northeast and Midwest) has incorporated measures to ensure or encourage natural gas plants to have access to sufficient fuel supply either by installing dual-fuel capabilities or having firm gas delivery contracts.[147]

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[144] FERC-NERC-Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, November 2021.

[145] FERC, 182 FERC ¶ 61,094, February 16, 2023, Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and NERC, EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1.

[146] See PJM, "PJM Files Changes to Capacity Market To Promote Reliability", October 13, 2023, accessed December 20, 2023. For further discussion, see Astrapé Consulting and Advanced Energy Economy, Getting Capacity Right: How Current Methods Overvalue Conventional Power Sources, March 30, 2022.

[147] FERC, 151 FERC ¶ 61,208, Order on Proposed Tariff Revisions, p. 28; Deborah Cooke, Overview of ISO-NE's Inventoried Energy Program V1, ISO-NE, October 1, 2019.

Several entities including NERC and FERC have been focused on reform efforts to address these various cold weather challenges affecting the electricity and gas systems.[148] The National Association of Regulatory Utility Commissioners (NARUC), NERC, FERC, and the North American Energy Standards Board (NAESB) have taken steps to improve the coordination between the gas and electricity sectors to ensure reliability as gas generation is increasingly used as a flexible resource.[149]

Electric grid emergencies during winter storms in Texas and the East Coast have also prompted policymakers to pursue weatherization measures that are aimed at ensuring that grid infrastructure remains resilient and functions adequately.[150]

E. Developing sufficient transmission to deliver power

THE NEED FOR SUFFICIENT TRANSMISSION

As load growth has been limited in the past decade, reliability concerns have focused more on the changing resource mix and less on building capacity to meet higher peak demand. This dynamic requires transmission to access low-cost resources in new locations. Going forward, increased electric demand growth re-introduces more traditional reliability needs met by building still more new resources (including demand response) and transmission facilities to meet increasing peak demand. These effects combine to drive a rising need for new transmission to support reliability in the future.

The NERC 2022 LTRA identifies "*insufficient transmission for large power transfers*" as a key insight from their assessment of trends that affect long-term reliability.

[148] For reform efforts, see National Association of Regulatory Utilities Commissioners (NARUC), Memorandum on the Creation of the Gas-Electric Alignment for Reliability (GEAR), 2023; FERC and NERC, FERC, NERC Encourage NAESB to Convene Gas-Electric Forum to Address Reliability Challenges, July 29, 2022; FERC, 182 FERC ¶ 61,094, February 16, 2023, Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and NERC, EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1.

[149] Regina Davis, New NARUC Gas-Electric Working Group to Address Growing Grid-Related Challenges, November 22, 2023; NERC, Reliability Guideline: Natural Gas and Electrical Operational Coordination Considerations, March 22, 2023; North American Energy Standards Board (NAESB), Gas Electric Harmonization Forum Report, July 28, 2023; FERC, FERC Approves Final Rule to Improve Gas-Electric Coordination, April 16, 2015.

[150] FERC, FERC Approves Extreme Cold Weather Reliability Standards, Directs Improvements, February 16, 2023; Tanya Eiserer and Jason Trahan, A year ago, Texas power plants weren't required to winterize. Now they are. But is that enough to keep the grid from failing in the next deep freeze?, WFAA, February 15, 2022.

Among other solutions such as grid enhancing technologies, building new transmission infrastructure will be needed to deliver new low-cost renewable supply to customers. To the extent such new supply will provide needed adequacy contributions, any delay in the new transmission impacts adequacy. While larger planning areas (such as ISOs/RTOs) can withstand fluctuations in adequacy levels associated with small changes or delays in transmission capacity, smaller standalone utilities may need to carefully coordinate the retirement of outgoing generators with development of both new transmission and new supply. This presents risks, as described by NERC in their 2023 Reliability Risk Priorities Report:[151]

> *"… other elements of resource adequacy (e.g., transmission development, generator retirements, pipeline construction, environmental permitting, and right-of-way acquisition) may require long and/or uncertain lead times to assure future reliability and resource adequacy of the system. Various elements may also need to be carefully sequenced to ensure reliability throughout the transition, and the interrelated nature and contribution of transmission, generation, and fuel sources must be appreciated and considered in resource adequacy assessments, energy reliability assessments, time lines, and deployments. This has been further exacerbated by a problematic supply chain, international trade, and import tariff issues that continue to be disruptive to plans and schedules."*
>
> *[…]*
>
> *"…construction of well-placed, highly resilient transmission is not keeping pace with other changes.* ***Transmission siting and permitting is historically arduous, and this combined with jurisdictional issues may result in insufficient timely construction of resilient-design, cross-regional transmission****." [emphasis added]*

President Robb states in his testimony before the US Senate Committee on Energy and Natural Resources that:

[151] NERC, 2023 ERO Reliability Risk Priorities Report, August 17, 2023.

> *"… the risk profile to customers is steadily deteriorating. Factors contribution [sic] to this deterioration include...increased demand due to electrification, coupled with slow development of new energy infrastructure needed to support grid resilience and the clean energy future."*[152]

GAPS IN MEETING RISING TRANSMISSION NEEDS

New transmission lines can be delayed due to fragmented processes that can intersect multiple state and federal agencies as well as local authorities, all backed by various laws and regulations.[153] This provides many paths to litigation for project opponents, creating an uncertain and extended timeline for deciding whether the project is in the public interest.[154] Furthermore, new technologies that allow existing transmission lines to be more fully utilized have in some cases been delayed as the underlying reforms in system planning and operations that are needed to implement them have not been carried out.

SOLUTIONS AND EXAMPLES TO MEET TRANSMISSION NEEDS

Grid-Enhancing Technologies (GETs) allow operators to increase utilization of existing transmission infrastructure, moving more power without the need to build new transmission.[155] By optimizing the flow of electricity over existing transmission lines, GETs such as dynamic line ratings, topology control, and advanced flow control can potentially allow more than twice the amount of new renewables to be interconnected relative to conventional transmission planning approaches.[156]

After many decades with relatively little policy attention, state lawmakers are recognizing the need for more consistent and predictable timelines for transmission siting, especially in light of the shift to renewable energy. In 2022, California passed AB 205 to give the California Energy

[152] James B. Robb, Testimony of James B. Robb, U.S. Senate Committee on Energy and Natural Resources, June 1, 2023, p. 1.

[153] National Governors Association (NGA), Transmission Siting And Permitting: How Governor Leadership Can Advance Projects, February 8, 2023, Section; National Council on Electricity Policy, Mini Guide on Transmission Siting: State Agency Decision Making, December 2021.

[154] Molly Robertson and Karen Palmer, Transmission 102: Building New Transmission Lines, Resources for the Future (RFF), September 22, 2023.

[155] DOE, Grid-Enhancing Technologies: A Case Study on Ratepayer Impact, February 2022.

[156] Bruce Tsuchida, et al., Unlocking the Queue with Grid-Enhancing Technologies, the Brattle Group, February 1, 2021

Commission exclusive siting authority over new transmission lines, with a set timeline for deciding qualifying siting requests.[157] The California Public Utilities Commission has also begun to implement a streamlined process for reviewing new transmission projects.[158] New York passed a bill to streamline transmission siting in 2020, and New Jersey in 2021 passed a bill centralizing siting authority over offshore wind cables in the Board of Public Utilities.[159] New Mexico established the Renewable Energy Transmission Authority in 2007 to facilitate the development of transmission projects, including as project co-developer. After many years without funding or staff, it was resuscitated in 2020, and in 2023 it broke ground on its high capacity interstate SunZia high-voltage DC transmission project.[160]

The federal government has taken a variety of major steps to facilitate new transmission siting and development. Most importantly, the 2021 Bipartisan Infrastructure Law included a provision strengthening existing federal authority over transmission siting in designated National Interest Electric Transmission Corridors.[161] The Biden Administration is in the process of making those designations, backed by a report which sets the foundation for significant transmission investment and a FERC Notice of Proposed Rulemaking to implement the siting decisions.[162] Recently, the Department of Energy (DOE) has also proposed to ease environmental reviews for certain transmission upgrades and rebuilds (as well as storage and solar projects) on federal land.[163] Tens of billions of dollars in funding to support transmission siting and development was included in the Bipartisan Infrastructure Law of 2021 and the Inflation Reduction Act (IRA) of

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157 Perkins Coie LLP, California Expands Energy Commission's Jurisdiction to Bolster Clean Energy Development, July 18, 2022.

158 CPUC, CPUC To Update Transmission Siting Regulations To Address Electricity Reliability and Climate Goals, May 18, 2023.

159 The Burns and McDonnell Team, Navigating New York's Article VII Process for Transmission Line Permitting and Design, 2021. Heather Richards, NIMBY-proof? N.J. takes major step on offshore wind, EnergyWire, July 23, 2021.

160 New Mexico Renewable Energy Transmission Authority (RETA), Annual Report, December 2021.

161 Boris Shkuta, et al., Electricity Transmission Provisions in the Bipartisan Infrastructure Bill, Bracewell LLLP, November 18, 2021.

162 DOE, National Transmission Needs Study, October 2023; Grid Deployment Office, "National Interest Electric Transmission Corridor Designation Process," accessed December 13, 2023; FERC, Docket No. RM22-7-000, May 8, 2023, Explainer on the Notice of Proposed Rulemaking regarding Applications for Permits to Site Interstate Electric Transmission Facilities (12/15/22).

163 Currently, upgrades or rebuilds of transmission lines that are "approximately 20 miles in length or less" are subject to reduced environmental reviews; The DOE proposes to remove this mileage limitation and expand the environmental review exemption to relocated transmission lines within existing right of ways or otherwise disturbed or developed lands. See DOE, National Environmental Policy Act Implementing Procedures: Proposed Rule, November 16, 2023.

2022, and the Biden Administration has implemented an array of transmission siting and funding initiatives, recently committing up to $1.3 billion for three large interstate transmission projects.[164]

The Biden administration says they have helped facilitate breaking ground on ten new high-capacity transmission projects since 2021, connecting 19.5 GW of new generation.[165] According to analysis by Bloomberg News (Figure 12 below), "*suddenly several big power-line projects in the US are moving ahead, bringing with them a flood of potential wind and solar power.*"[166] Americans for a Clean Energy Grid and Grid Strategies have identified a further 36 projects totalling approximately 132 GW of transmission capacity that are in "ready to go" status.[167] The authors find that "*recent movement on the permits for these projects also suggests that the pace of federal permitting has improved as internal and interagency delays holding up some projects have been resolved."*[168]

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[164] The White House, Fact Sheet: The Biden-Harris Administration Advances Transmission Buildout to Deliver Affordable, Clean Electricity, November 18, 2022; The White House, Fact Sheet: Biden-Harris Administration Announces Historic Investment to Bolster Nation's Electric Grid Infrastructure, Cut Energy Costs for Families, and Create Good-paying Jobs, October 20, 2023; Grid Deployment Office, "Transmission Facilitation Program First Round Selections," accessed December 12, 2023.

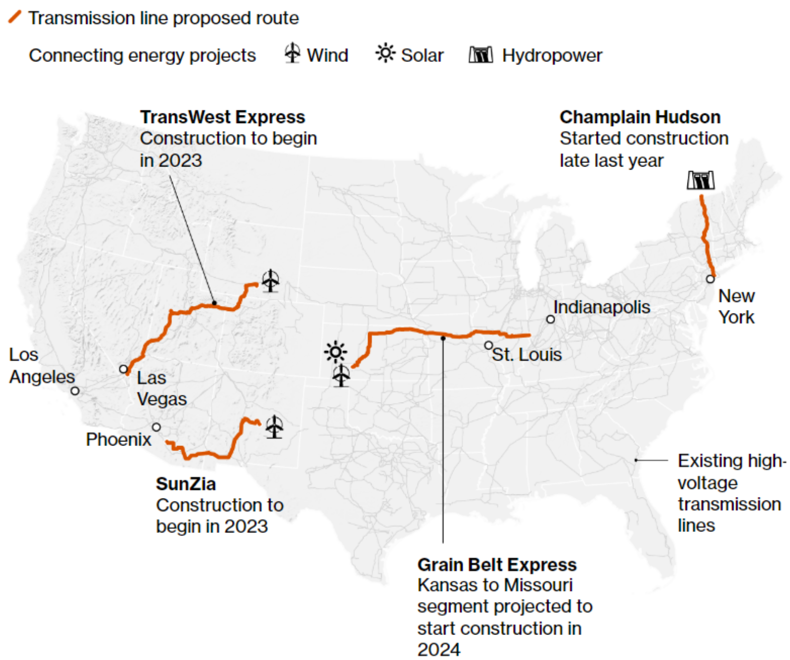
[165] The White House, Fact Sheet: Biden-Harris Administration Announces Historic Investment to Bolster Nation's Electric Grid Infrastructure, Cut Energy Costs for Families, and Create Good-paying Jobs, October 20, 2023.

[166] Brian Eckhouse, et al., Billion-Dollar Power Lines Finally Inching Ahead to Help US Grids, Bloomberg, March 6, 2023.

[167] Zachary Zimmerman, et al., Ready-To-Go Transmission Projects 2023, Americans for a Clean Energy Grid and Grid Strategies, September 2023, pp. 4-5.

[168] Zachary Zimmerman, et al., Ready-To-Go Transmission Projects 2023, Americans for a Clean Energy Grid and Grid Strategies, September 2023, p. 6.

FIGURE 12: TRANSMISSION PROJECTS MOVE AHEAD AFTER YEARS OF PERMITTING



Notes and Sources: Brian Eckhouse, et al., Billion-Dollar Power Lines Finally Inching Ahead to Help US Grids, Bloomberg, March 6, 2023.

Separately, membership in an ISO/RTO or other pooled long-term adequacy program offers the advantage that the impact of any one project's delay is relatively smaller compared with the entire pool. This reduces the need to carefully coordinate the retirement of old generators with the initial operating date of new generators. With the advent of the Western Resource Adequacy Program, nearly all of the United States will soon be covered by such pooling arrangements.

F. Reforms to optimize reliability of a clean energy grid

The electric grid is constantly evolving, and the institutions of the power sector continuously learning, improving, and adapting. The evolution of the coming years will progressively shift the relative size and importance of today's challenges, but at a high level it is not likely to categorically transform them. As in the past, tools and processes to manage those challenges will need to evolve to match their changing nature, and innovations will build off prior developments.

The accelerating availability of cost-effective clean energy resources—from technologically improved wind and solar systems to grid enhancing technologies to the next generation of advanced storage—hold the promise of largely decarbonized grid that can serve expanding demand with improved reliability characteristics. These changes are being driven by the economics of lower cost resources, federal and state policies such as the IRA and renewable portfolio standards, consumer preferences, and to some extent by current and proposed environmental regulations. Ensuring all aspects of reliability requires a comprehensive and coordinated approach from grid operators and their regulators.

As explored in detail above, and summarized below, ISOs/RTOs and other grid operators have numerous tools in their reliability toolkits that can be applied to the future clean energy grid. In some cases, operators will be able to apply existing tools, adapted somewhat to a changing grid, and in other cases operators must pursue more foundational reforms to better respond to the emerging challenges and strengths of the future grid.

Grid operators have multiple options for addressing the changing needs and incorporating the growing value of the future grid. Table 2 summarizes a selection of how new solutions can be explored within this new context.

TABLE 2: EXISTING TOOLS WILL SHIFT IN IMPORTANCE, EVOLVE, AND ITERATE TO MATCH EVOLVING SYSTEM NEEDS AND STRENGTHS

	Shifting Challenges	Shifting Solutions
Capacity adequacy and Long-Term Energy Adequacy	• More variability in potential scarcity conditions • Increased demand for electricity with electrification of other sectors	• Shift to year-round adequacy evaluations (e.g., via new metrics) and away from peak-hour reserve margin metric • Improved precision of probabilistic reliability models, longer weather histories • Potential to incorporate non-probabilistic scenario-based planning of extreme weather for resilience
Operational Energy Adequacy	• More variability and uncertainty • Potential to unlock new sources of flexibility among customer-side resources, batteries, and curtailed renewables	• Greater importance on operational scheduling and dispatch tools, including forecasting • New ancillary services for ramp and other flexibility services to operate and retain or attract flexible resources • Improved pricing of flexibility services in ISOs/RTOs
Operating Reliability	• Faster dynamics and more responsive resources • More computer-mediated transient responses and need to manage configurations, programming, and models • Resources can provide services all the time at lower cost	• Greater role for stability • Requirements for grid-forming inverters • Potentially more synchronous condensers • More HVDC for long-haul access to remote, low-cost resources and stability improvement

These reliability reforms, designed to achieve reliability under growing dependence on clean energy resources, have variously been pursued at the major U.S. grid operators. The extent of reform broadly tracks their relative deployments of wind, solar, and storage. In Table 3 below, we present examples of such reforms across the four reliability areas (with "long-term adequacy" combining both capacity adequacy and long-term energy adequacy) spanning a sample of four ISOs/RTOs representing different geographies and varying levels of renewable deployment.

As shown in row A of Table 3, PJM and MISO have both invested significant efforts in studying the potential reliability concerns associated with a changing resource mix, producing the Energy Transition series and the Renewable Integration Impact Assessment (RIIA) report, respectively.[169]

[169] The RIIA report is a useful reference guide for readers who wish to engage in more detailed research into challenges and enhancements posed by renewables for resource adequacy, long-term energy adequacy, operational energy adequacy, and operating reliability. See PJM, "Ensuring a Reliable Energy Transition," 2023, accessed December 19, 2023; MISO, MISO's Renewable Integration Impact Assessment (RIIA), February 2021.

ERCOT and CAISO have conducted more narrow efforts recently focused on operating reliability with inverter-based resources.

Rows B – D describe aspects of energy adequacy reforms in the long-term adequacy planning constructs. With varying levels of wind and solar, these operators have all pursued or are in the process of proposing ELCC, the first step towards a comprehensive long-term energy adequacy planning construct. PJM is unique among them in proposing a complete conversion to hourly analysis for all long-term adequacy purposes.

Rows E – H describe enhancements to Operating Reserves, with many examples of new types of reserves and expanded procurement of existing types. 5-minute settlements refers to a real-time wholesale energy market which measures and pays generator output on the basis of 5-minute intervals, thereby extracting additional flexibility capability from the fleet by sending more precise intra-hour price signals. Improved day-ahead resource schedule optimization could include any of a number of enhancements to the day-ahead energy market scheduling construct that would incentivize or otherwise secure more flexibility. The two extant examples are: (1) storage optimization, whereby the hourly schedule of battery storage resources is developed to optimize grid value in light of operating limitations related to the amount of energy that can be stored; and (2), in CAISO, better integration of various stages of the day-ahead scheduling process.

Rows I – K describe enhancements to operating reliability.

TABLE 3: ISOS/RTOS PURSUING RELIABILITY ENHANCEMENTS SUITED TO RENEWABLE DEPLOYMENT

		ERCOT	CAISO	MISO	PJM
	[A] Inverter –based resource integration studies & transition efforts	Impact of Growth in Wind and Solar on Net Load; Inverter-Based Resource Working Group	Reliability Standards to Address Inverter-Based Resources	RIIA, Reliability Attributes effort	Energy Transition series; 2014 Renewable Integration Study series
Long-Term Adequacy Model	[B] Includes all hours of year	N/A	Hourly ELCC for clean resource long-term adequacy values	Hourly ELCC for clean resource long-term adequacy values	Proposed comprehensive hourly construct
Long-Term Adequacy Model	[C] Accounts for extreme weather over decades	N/A	Yes for clean resources	Yes for clean resources	Proposed for all resources and overall capacity requirement
Long-Term Adequacy Model	[D] Accounts for extreme weather effects on availability	N/A	No, except for ELCC	No, except for ELCC	Proposed for all resources and overall capacity requirement
Operational Energy Adequacy	[E] Increased procurement of uncertainty reserves	Day-ahead non-spin reserve and online reserves	Day-ahead spinning and non-spinning reserves	No*	Synchronized, Primary, Secondary Reserves
Operational Energy Adequacy	[F] New types of uncertainty reserves	ERCOT Contingency Reserve Service, Dispatchable Reliability Reserve Service (pending)	Flexible Ramping Product, Imbalance Reserve (proposed)	Short-Term Reserve, Ramp Capability Product	Secondary Reserves
Operational Energy Adequacy	[G] 5-minute energy settlements	Yes	Yes	Yes	Yes
Operational Energy Adequacy	[H] Improved day-ahead resource schedule optimization	No	Storage optimization, other day-ahead enhancements	No	No
Operating Reliability	[I] Ensuring voltage control	Yes	Yes	Yes	Yes
Operating Reliability	[J] Ensuring frequency response	Require, monitor, & procure	Require, monitor, & procure	Require & monitor	Require & monitor
Operating Reliability	[K] Ensuring other Essential Reliability Services	Monitor system-wide inertial response, monitor & procure voltage disturbance performance	N/A	N/A	N/A
	[L] Percent energy from wind & solar	2012: 9%; 2022: 31%	2012: 6%; 2022: 26%	2012: 7%; 2022: 16%	2012: 2%; 2022: 5%

Notes and Sources:

[A] [As linked in the table]

[B] ERCOT runs an energy-only market; CA capacity accreditation for wind/solar based on monthly ELCC; CPUC, 2020 Qualifying Capacity Methodology Manual, November, 2020, pp. 13-14; CPUC, Decision 17-06-027, June 29, 2017, Decision Adopting Local and Flexible Capacity Obligations for 2018 and Refining the Resource Adequacy Program, p. A-4; MISO capacity accreditation for wind/solar based on seasonal ELCC, capacity accreditation for thermal resources based on historical availability during periods of highest risk per season, see MISO, Planning Year 2023-2024 Wind and Solar Capacity Credit Report, March 2023, p. 7; MISO, Business Practice Manual 11, October 1, 2023, Appendix Y; PJM proposes applying ELCC to all generators, see PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, Docket No. ER24-99-000, pp. 23-27, 41-43.

[C] See above note on ERCOT; CPUC ELCC values used for 2023 Mid-Term Reliability procurement based on 22 years of weather data, see Astrapé Consulting and E3 Consulting, Incremental ELCC Study for Mid-Term Reliability Procurement, January, 2023, p. 20; MISO ELCC based on 30 years of weather data, see MISO, Planning Year 2023-2024 Wind and Solar Capacity Credit Report, March 2023, p. 9; PJM proposed ELCC calculations for all resources based on 30 years of weather data, see PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, Docket No. ER24-99-000, pp. 41-43.

[D] See above note on ERCOT; CPUC ELCC calculations for solar and wind do not account for extreme weather in base case but do feature an extreme weather sensitivity, see Astrapé and E3 Consulting, Incremental ELCC Study for Mid-Term Reliability Procurement, January, 2023, pp. 45-48; MISO, Planning Year 2023-2024 Wind and Solar Capacity Credit Report, March 2023; PJM proposed ELCC modeling accounts for resource unavailability as function of weather, see PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, Docket No. ER24-99-000, pp. 44-45.

[E] Following Strom Uri, ERCOT updated the ORDC used to procure operating reserves, see ERCOT, 2022 Biennial ERCOT Report on the Operating Reserve Demand Curve, October 31, 2022, p. 6. ERCOT also increased reserve procurement after implementing Contingency Reserve Services, see Carrie Bivens, IMM Concerns with the AS Methodology and Recommended Improvements, September 22, 2023, p. 4. CAISO calculates day-ahead reserve requirements based on the maximum of A) 6.3% of load forecast B) largest single contingency and C) 15% of forecasted solar production (similar calculation for real-time reserves), day-ahead reserve procurement in 2022 increased by an average of 3% relative to prior year, see CAISO, 2022 Annual Report on Market Issues & Performance, July 11, 2023, p. 146. *In 2021, MISO proposed raising the price cap of its ORDC (while maintaining same maximum quantity procured at the foot), while this reform does not directly increase the quantity procured, it could incentivize greater resource participation in operating reserves due to higher revenue opportunities, MISO, Scarcity Pricing Evaluation, May 2021, pp. 16-17; PJM implemented an increase on all operating reserve requirements until further notice but is concurrently pursuing additional reforms, see PJM, Synchronized Reserve Requirement Reliability Update, May 18, 2023, p. 1; PJM, Reserve Certainty Problem/Opportunity Statement, August 24, 2023, pp. 1-4.

[F] ERCOT, Introduction to FFR Advancement and ERCOT Contingency Reserve Service (ECRS) Projects), June 16, 2022, p. 6; ERCOT, Board Report on Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserves, February 12, 2019; HB 1500 requires ERCOT to implement a new ancillary product called Dispatchable Reliability Reserve Service by December 2024; Texas Legislature, H.B. No. 1500, June, 2023, pp. 20-21; Kenan Ögelman, DRRS Discussion, ERCOT, July 27, 2023, pp. 1-7; CAISO, "Flexible ramping product," 2023; CAISO, "Revised Final Proposal: Day-Ahead Market Enhancements, May 1, 2023, p. 5; MISO, BPM 002, September, 30, 2022, pp. 52-55; PJM, Manual 11, November 15, 2023; CAISO, Day-Ahead Market Enhancements, May 2, 2023.

[G] FERC, 155 FERC ¶ 61,276, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, June 16, 2016.

[H] ERCOT, MISO, and PJM not currently pursuing revisions to storage optimization model; CAISO storage optimization accounts for energy limitations, inter-temporal conditions, and state-of-charge limits, CAISO, Special Report on Battery Storage, July 7, 2023, pp. 5-6.

[I] ERCOT, ERCOT Nodal Operating Guides, May 27, 2022, Section 2.7; CAISO, Voltage and VAR Control, December 13, 2022; MISO, Reactive Supply and Voltage Control From Generation or Other Sources Services, December 1, 2022; PJM, Reactive Supply and Voltage Control from generation or Other Sources Service, September 1, 2018.

[J] Julia Matevosyan, Fast Frequency Response in the Texas Power System, September 2021; CAISO, Fifth Replacement Electronic Tariff: Section 8, February 11, 2023, p. 24; MISO, Markets of the Future: A Reliability

Imperative Report, November 2021, pp. 16, 24; PJM, Manual 12: Balancing Operations, September 9, 2023, pp. 30-32.

[K] Ensuring voltage disturbance performance under high inverter-based resource deployment is not yet commonly performed in system planning studies nor in operations (with the exception of ERCOT); Inertial response on the Eastern Interconnect and Western Interconnect is expected to be ample for many years due to the size of the interconnections; Operating reserves are secured in all ISOs/RTOs as ancillary services; Active power control (ramp) is secured in all ISOs/RTOs as day-ahead and intraday scheduling, see ERCOT, Nodal Operating Guides – Section 2: System Operations and Control Requirements, subsection 2.9; Current Protocols – Nodal: Section 3: Management Activities for the ERCOT System, December 1, 2023; ERCOT, Dynamics Working Group Procedure Manual, October 5, 2023, Revision 20; ERCOT, ERCOT Interconnection Inertia Analysis.

[L] ERCOT, "Generation," accessed December 17, 2023; California Energy Commission, "Electric Generation Capacity and Energy," accessed December 17, 2023; Potomac Economics, 2012 State of the Market Report For the MISO Electricity Markets, June 2013, Analytical Appendix; Potomac Economics, 2022 State of the Market Report For the MISO Electricity Markets, June 15, 2023; Potomac Economics, 2012 State of the Market Report For PJM, 2013, Vol. 2, Section 2; PJM, Reports and Notices, accessed December 17, 2023.

MAXIMIZING VALUE FROM ENABLING TECHNOLOGIES FOR RELIABILITY

Changing reliability needs in the future grid will require adaptations and new solutions. It will be critical in this endeavor to maximize the flexibility value of resources in the grid, including full utilization of new technologies that promise to provide ample reliability services.

New technologies offer promising reliability capabilities. For example, wide-scale nationwide deployment of solar will provide abundant energy coincident with the two or three peak hours of demand in late summer afternoons, significantly mitigating the challenge of meeting demand during such hours. Deployment of wind power, very significant in some areas, is expected to likewise provide abundant supply during many—although not all—extreme winter events (especially when properly winterized). Greater deployment of batteries, often installed to meet the tightest operational periods, will further deepen the pool of low-cost flexibility in the other hours of the year. Newly available grid-forming inverter technology, especially when backed by batteries, promises to provide all of the same Essential Reliability Services of conventional generators and synchronous condensers. And, increasing deployment of flexible, internet-connected devices such as electric car chargers and heat pumps provides the opportunity for tapping into large quantities of low-cost flexibility.

Four enabling technologies stand out as providing clean flexibility value to match the rising need: battery storage, flexible demand, HVDC transmission, and regional wholesale markets. Further, the modular nature of solar and storage unlocks local, small-scale generation options in the form of distributed energy resources that can provide a key end-user resilience benefit as electricity is increasingly relied on for basic needs like heat and transport.

INCORPORATING NEW STORAGE RESOURCES INTO THE RELIABILITY FRAMEWORK

Grid storage technologies provide ample flexibility, and falling battery costs present a well-timed opportunity to meet the rising value and need for flexibility. These technologies enable greater grid flexibility, produce more precise ancillary service response, provide energy-firming capabilities for intermittent resources, and serve as a source for fast ramping needs that will become more important in the future.

To better incorporate and evaluate the reliability value of storage, grid operators have incorporated storage simulations into long-term adequacy modeling; have added day-ahead scheduling functionality that takes optimal advantage of the reliability capabilities of storage; and worked to ensure artificial barriers to participation in all wholesale markets are not restraining open competition from this relatively new resource type. [170]

Battery resources use the same inverter-based technology that wind and solar generation use to produce AC power. Therefore, efforts to operationalize the operating reliability functionality of inverter-based resources also applies to batteries. In some cases, such as steady-state voltage regulation, batteries provide uniquely superior Essential Reliability Service capability relative to other resource types, including conventional resources, provided that they are configured properly to realize such benefits.

FLEXIBLE DEMAND

In the future, greater integration and deployment of smart grid-connected control and communication technologies into consumer products and end-use equipment will enable more flexible demand, which can respond indirectly to price signals or directly to control signals. [171] Especially as new demand comes online from consumer services that have some inherent underlying flexibility (e.g., schedules for car charging or pre-heating a water heater, as well as

170 See references to ISO/RTO ELCC models in PJM and California: CAISO, Special Report on Battery Storage, July 7, 2023, pp. 5-6; FERC, 162 FERC ¶ 61,127, February 15, 2018, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators.

171 David Podorson, Grid Interactive Water Heaters – How Water Heathers Have Evolved into a Grid Scale Energy Storage Medium, American Council for an Energy Efficient Economy, 2016; Jie Cai and James E. Braun, Using HVAC Systems for Providing Power Grid Ancillary Services, International High Performance Buildings Conference, July 2018; Clean Energy Institute, "Data Center Energy Management," University of Washington, accessed December 4, 2023; Timothy Lipman, et al., Total Charge Management of Electric Vehicles, California Energy Commission, December 2021.

load shifting among data centers), the outlook for flexible demand that mitigates peak consumption is positive. [172]

Flexible demand is able to positively impact reliability by providing high-value services, such as geographically-targeted demand reductions, load building, and system balancing through active demand management.[173] Aggregated portfolios of flexible demand, known as Virtual Power Plants, can even provide power-plant levels of capacity and could be a cost-effective alternative to conventional resource options.[174]

HVDC TRANSMISSION

HVDC transmission is a decades-old technology that had traditionally been used for bulk power transfers over long distances, or in other circumstances that are difficult for AC technology (such as close to large urban centers or between non-synchronized interconnections). HVDC can be used to address several growing needs: access to remote, low-cost renewables; bulk interregional transfer of clean energy to support energy adequacy; and support the growing value of regionalization in wholesale markets. At the same time, HVDC transmission solutions that take advantage of new converter technologies (which are similar to inverter technologies for wind, solar, and battery resources, and are often counted as a type of inverter technology) can meet those same use cases more effectively. The new converter stations can provide a variety of Essential Reliability Services; contribute to stability of the AC grid; more effectively control the flow of power and manage congestion on the AC grid; and can support flexibility needs, especially when spanning different grid operators. A variety of reforms can be pursued by grid operators to best take advantage of these capabilities.[175]

RELIABILITY EFFECTS OF EXPANDED REGIONAL WHOLESALE MARKETS

ISO/RTO markets offer advantageous access to a wide pool of resources and abundant flexibility in their scheduling. Flexibility needs are addressed through diversification of uncontrollable

[172] Cara Goldenberg, et al., Demand Flexibility: the Key to Enabling a Low-Cost, Low-Carbon Grid, Rocky Mountain Institute, February 2018; Elliott J. Nethercutt, Demand Flexibility within a Performance-Based Regulatory Framework, NARUC, January 2023.

[173] Ryan Hledik, et al., The National Potential for Load Flexibility: Value and Market Potential Through 2030, The Brattle Group, June 2019.

[174] Ryan Hledik and Kate Peters, Real Reliability: The Value of Virtual Power, The Brattle Group, May 2023.

[175] For a listing of these reforms and a more detailed explanation of the capabilities and applications of modern HVDC technology, see Johannes P. Pfeifenberger, et al, The Operational and Market Benefits of HVDC to System Operators, September 2023.

demand and supply availability across a variety of geographies driving different patterns in supply and demand, smoothing out otherwise-steep changes in supply-demand balance that would require significant resource flexibility to address. Pooling of resources also augments system flexibility because grid operators can quickly pull from a large and diverse pool of flexible resources to meet fluctuations in load.

Wholesale market participation supports resource adequacy by broadening and diversifying the pool of supply to which resources have access; as a result, participants in wholesale markets need to carry relatively lower planning and operating reserves to maintain similar or improved levels of reliability.[176]

Capacity markets create a dependable reliability feedback mechanism, as price signals within the market effectively indicate the need to procure additional capacity in response to any retirements that may threaten reliability.[177]

Regional resource adequacy markets, such as the ISOs/RTOs and the under-development Western Resource Adequacy Program, also enable seamless coordination across a wide area during emergencies, such as scheduling ahead of emergencies, which helps tackle any reliability challenges faced during these events. Finally, improved coordination in the case of contingency events helps uphold system stability. In the example of the EIM, real-time data sharing increases the visibility of contingencies elsewhere on the system that could pose threats to reliability, thus allowing system operators to take proactive actions to avoid cascading reliability events. In addition, efficient dispatch increases the speed by which replacement generation can be delivered following contingency events.

DISTRIBUTED ENERGY RESOURCES FOR LOCAL RESILIENCE

Controllable resources that are physically connected to local distribution wires or through a customer facility are called “distributed energy resources.” Some distributed solar, storage, and solar+storage hybrid systems are equipped to provide emergency back-up power, improving local resilience to all kinds of service interruptions. Applications include residential systems (replacing conventional gasoline-powered backup generators); communities in remote areas without grid access; commercial facilities that require instantaneous backup power (such as data

[176] For example, the WEIM claims a 59% reduction in flexible reserves across its footprint since its implementation, see CAISO, Western Energy Imbalance Market Benefits Report, October 31, 2031, Third Quarter 2023, p. 3.

[177] Jim Wilson, Maintaining the PJM Region’s Robust Reserve Margins, Wilson Energy Economics, May 2023.

centers); and community microgrids in areas prone to service interruptions.[178] This functionality is enhanced with flexible loads as well as vehicle-to-home systems such as that available on the Ford F-150 Lightning pickup truck.[179] Such functionality grows in value as people become increasingly dependent on electricity as the sole source of basic needs like heat, transportation, and cooking.

V. Flexibilities in Compliance with Environmental Regulations

As the previous sections demonstrate, grid operators are facing numerous reliability challenges as the electricity sector evolves. These challenges are driven primarily by changing economics, technology advances, and increasing vulnerability to extreme weather. Ensuring grid reliability over the next decade requires planning for sufficient amount of resources with the appropriate reliability attributes, expanding capability of the grid infrastructure, and bringing new generation resources online in a timely manner.

Environmental and public health regulations are often cited as a driver of reliability concerns.[180] Although new regulations may increase operating costs, require technology upgrades, and contribute to earlier retirements for some facilities, reports on recent reliability events (e.g., Winter Storm Uri, heat wave brownouts) demonstrate that insufficient resource adequacy planning targets and vulnerabilities of infrastructure to extreme weather conditions were the main causes, not environmental regulations. To the extent specific environmental regulations accelerate the ongoing retirement of existing fossil fleet being replaced by cleaner resources, there are proven policy mechanisms to allow grid operators the flexibility to ensure reliability. Going forward, addressing the existing needs for capacity and infrastructure through evolving planning tools and mechanisms would likely address most, if not all, reliability concerns associated with new regulations.

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[178] Tesla, Powerwall, accessed December 5, 2023; Alaska Microgrid Group, accessed December 5, 2023; Microsoft Azure, Inside a Microsoft datacenter, accessed December 5, 2023; Pacific Gas and Electric (PG&E), Microgrids & remote grids, 2023, accessed December 5, 2023.

[179] Scott Evans and Williams Walker, How the Ford F-150 Lightning Can Power Your Whole House, MotorTrend, May 18, 2022.

[180] Cathy McMorris Rodgers and Frank Pallone Jr., Letter to Administrator Regan, Congress of the United States, April 19, 2023.

Rather than mandate retirements, environmental regulations typically specify standards for emissions (e.g., rates per unit of fuel use or quantities per hour or per year), compliance deadlines, and multiple compliance options with varying degrees of costs and effectiveness to reduce emissions. To allow plant owners, state regulators and system planners to develop economic compliance plans without having to sacrifice system reliability, environmental regulations typically include various forms of compliance flexibilities.

The key types of compliance flexibilities in U.S. federal environmental regulations that will help as tools to reduce adverse impacts on electric grid reliability can be summarized into four general categories: (1) absence of an obligation to reduce generation output or retire a power plant; (2) multiple compliance options that would allow power plants to continue operating during periods with high reliability needs; (3) advance notice to implement compliance plans; and (4) emergency exemptions as a last resort option for maintaining reliability.

A. No obligation to reduce generation output or retire a power plant

Across various environmental regulations, the Environmental Protection Agency (EPA) avoids mandating that electric generating units either reduce generation output or retire in order to meet compliance standards. This allows for owners of individual power plants to make economic decisions (subject to approval by their state regulators) on whether to retire or choose other compliance options. Such an approach is taken in the Mercury and Air Toxics Standards (MATS) rule, the Good Neighbor Plan (GNP) rule, and other federal environmental regulations that affect power plants. Even though reducing generation output or retiring a power plant is typically an option for generators, EPA regulations typically provide alternative methods for compliance that we will discuss in the next section.

The compliance flexibility of generators and grid operators to consider the economic feasibility of impacted units, rather than being mandated to shut down generation capacity, mitigates potential adverse impacts of environmental regulations on grid reliability.

B. Multiple compliance options

While the EPA regulations do increase costs for emission-intensive generation plants by requiring abatement of emissions, plant owners typically have multiple compliance options with varying effectiveness, cost, and lead time. In general, compliance options can include market-based solutions such as allowance trading, operational solutions such as reducing (or shifting the time of) generation output, and equipment solutions such as installing and operating activated carbon injection (ACI) or selective catalytic reduction equipment. Finally, there is always the option for generating units to be retired if their operators deem the continued operations to be uneconomic. This section describes various compliance options available to plant owners and then provides specific examples of implementation in several recent environmental regulations: the MATS, the GNP, and the proposed EPA 111(d) rule for greenhouse-gas (GHG) emissions from power plants (111(d) rule).

CO-FIRING OR FULL CONVERSION TO OTHER FUELS

Another compliance option is to "co-fire" at power plants that rely on emission-intensive fuels (especially coal generators) to blend in low-emission fuels such as natural gas or biomass. For example, regulated pollutants in the MATS and GNP are emitted exclusively or to a much greater degree when burning coal compared to burning natural gas or biomass. Additionally, under the proposed 111(d) rule, one compliance pathway for power plants that burn natural gas is to co-fire gas with clean hydrogen.

As for natural gas, coal-fired units typically have much higher SO_2 and NOx emissions rates compared to natural gas-fired units.[181] Natural gas also results in roughly half of CO_2 emissions per unit of heating value.[182] Beyond the clear benefits to emissions as a result of co-firing, there may also be other benefits such as faster ramping, lower maintenance costs, and more adaptability related to coal supply.[183]

If co-firing of a power plant is not sufficient to meet emission targets, power plants also have the option to convert their fuel supply completely. As an example, between 2010 and 2019, 39.6 GW of coal-fired generation capacity was converted to burn natural gas.[184]

Either co-firing or converting fuels would retain continued operation of existing plants, hence averting the need to plan for replacing lost generation capacity.

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181 U.S. Government Accountability Office, Air Emissions and Electricity Generation at U.S. Power Plants, April 18, 2012.

182 EIA, Natural Gas Explained: Natural Gas and the Environment, November 7, 2022.

183 Andover Technology Partners, Natural Gas Cofiring for Coal-Fired Utility Boilers, February 12, 2022, p. 7.

184 EIA, Today in Energy: More than 100 coal-fired plants have been replaced or converted to natural gas since 2011, August 5, 2020.

EMISSIONS CONTROL EQUIPMENT TECHNOLOGIES

Plant owners typically have multiple options for emissions control equipment technologies to comply with a given environmental regulation.

For example, for reducing NO_x emissions rates, equipment choices include selective catalytic reduction systems, selective non-catalytic reduction (SNCR) systems, and combustion controls. Combustion controls reduce NO_x by controlling the characteristics of the combustion, such as temperature. Selective catalytic reduction and SNCR systems remove NO_x emissions after the combustion. Combustion controls like low-NO_x burners and overfire air are much cheaper to implement but also exhibit lower emissions removal abilities compared to post-combustion control equipment.[185] SNCR can remove between 30-70% of NO_x emissions, while selective capacity reduction can remove about 90% of emissions, albeit at a higher cost.[186]

For SO_2 emissions, technology choices include limestone forced oxidation (LSFO) scrubbers, lime spray dryer (LSD) scrubbers, and dry sorbent injection (DSI).[187] All of these methods involve spraying the flue gases, but with either dry or wet solvents. The applicability of these largely depends on the sulfur content of the coal used, as LSD does not effectively mitigate emissions from coals with sulfur content above 3 lbs/MMBtu. Both LSFO and LSD methods achieve approximately 90% reduction in emissions while DSI has lower emissions removal at lower cost.[188]

AVERAGING OF EMISSIONS (ACROSS GENERATION UNITS AND TIME)

Environmental standards are often set based on emission rates, which take the volume or mass of emissions divided by the Btus of fuel or the MWhs of electricity produced. These rates can change dramatically from hour to hour which could impact compliance with regulations. When environmental standards allow for averaging of emissions rates across longer periods of time, short peaks of high emissions rates tend to even out. Standards can have averaging times ranging

[185] Integrated Flow Solutions, "Power Plant NO_x Reduction—SCR vs SNCR Technology Which is better?," December 20, 2018, accessed November 28, 2023.

[186] Integrated Flow Solutions, "Power Plant NO_x Reduction—SCR vs SNCR Technology Which is better?," December 20, 2018, accessed November 28, 2023; EPA, Emission Control Technologies, March 2023, p. 5-7.

[187] EPA, Emission Control Technologies, March 2023, p. 5-1.

[188] R. K. Srivastava and W. Jozewicz, Flue Gas Desulfurization: The State of the Art, Journal of the Air and Waste Management Association, December 2011, Vol. 51, No. 12, p. 1676; EPA, Emission Control Technologies, March 2023, p. 5-1.

from multiple hours to multiple years. This allows power plants to meet short, high demand, periods without exceeding emissions rate limits.

Additionally, some regulations (such as MATS) allow for averaging of emissions across several generating units located together at a single large plant.[189] If such a plant has units with lower emissions rates than other units at the same plant, this averaging can help meet standards for the power plant as a whole.

REDUCING GENERATION OUTPUT

Another compliance option under mass-based regulations is to reduce generation output at lower-value times during the emissions measurement window. For example, to comply with the GNP rule for reducing NOx emissions during the ozone season (May through September), a power plant could have the option to either reduce the generation output during the ozone season or shift a portion of the generation output to other months of the year, rather than paying for allowances. With this compliance mechanism, power plants can choose to generate during the hours with the tightest supply conditions while reducing the total amount of emissions produced.

ALLOWANCE TRADING

Some EPA regulations provide the owner of an affected power plant the option to submit an allowance for each unit of emissions from that plant, instead of reducing the emissions. Such allowances are obtained either through allocation to owners of power plants (typically based on historical share of emissions, generation output, or heat input), or through purchase from a market where emissions allowances are traded at prices reflecting the demand and supply of such allowances. Power plant owners that have low-cost options to reduce emissions (e.g., by using a fuel with low emissions content) relative to the market price of allowances could reduce emissions and then either bank their unused allowances for use in a later period, or sell them at market price. Meanwhile, the plant owners with high-cost mitigation options relative to the market price of allowances would find it more economic to buy allowances instead of reducing their emissions. This ability to trade emissions allowances among power plants reduces total compliance costs and provides compliance flexibility to generate power (and buy allowances) during hours when power system conditions are tight.

[189] EPA, Building Flexibility with Accountability into Clean Air Programs, August 8, 2023.

An example of a successful allowance trading program for power plants is the SO_2 cap-and-trade program, created as part of the Clean Air Act Amendments of 1990.[190] The program affected more than 3,200 fossil-fueled electric generating units by the year 2000. Initially, units were given allowances based on their 1985-1987 fuel usage.[191] The original emission cap decreased national emission allowances by 3.5 million tons per year from 1995-1999. SO_2 emissions eventually decreased by 36% from 1990 to 2004, while electricity generation from coal-fired units increased by 25% over the same period.[192] More recent regulations such as the Cross-State Air Pollution Rule (CSAPR) and Good Neighbor Plan have also incorporated emissions trading.

RETIREMENT

As mentioned above, owners of power plants also have the option to retire a plant instead of investing in any emissions control equipment, purchasing allowances, or changing plant operations. Ample time between the time a regulation is finalized and the time the compliance period starts allows for planning to replace lost reliability attributes (such as firm capacity, flexibility, ramp up, or other Essential Reliability Services) from such retired plants with new resources. Some regulations build in additional time to plan for retirement—for example, the proposed 111(d) rule, issued in 2023, would allow an existing coal plant to operate for over a decade before retiring while avoiding the most stringent emissions standard for coal units.

EXAMPLES OF COMPLIANCE OPTIONS IN RECENT ENVIRONMENTAL REGULATIONS

Many regulations include a variety of mechanisms to provide options for power plants. The goal is to provide a wide assortment of pathways to meet standards so that U.S. generators with different profiles can all find a way to comply with the standards. The following sections describe how recent regulations incorporate the above-mentioned mechanisms and a few unique options.

Mercury and Air Toxics Standards

MATS currently regulates three groups of pollutants through numeric emission limits: (1) mercury; (2) non-mercury hazardous metals; and (3) acid gases. MATS includes many of the

[190] This program did not go into effect until 1995.

[191] Richard Schmalensee and Robert N. Stavins, Lessons Learned from Three Decades of Experience with Cap and Trade, Review of Environmental Economics and Policy, Winter 2017, Vol. 11, No. 1.

[192] Richard Schmalensee and Robert N. Stavins, Lessons Learned from Three Decades of Experience with Cap and Trade, Review of Environmental Economics and Policy, Winter 2017, Vol. 11, No. 1.

above options for compliance plus a few unique compliance flexibility mechanisms. After finalization of the rule, many stakeholders and outside experts expected the impact of the standards to be much more drastic than the observed impact.[193] This difference between expectations and reality is largely attributable to the impact of compliance flexibility incorporated into the rule. Unique to MATS are two compliance flexibility mechanisms related to emissions reporting. First, for emissions of non-hazardous metals and acid gases, power plants had a choice of two or three potential regulatory options. For acid gases, U.S. generators could choose to meet standards for hydrochloric acid (HCl) ***or*** SO_2. For non-mercury metals, units can choose between meeting limits for particulate matter, total metal concentrations, or individual metal emissions.[194] Second, MATS gave the option to report emissions relative to MMBtus or relative to MWh (i.e., with respect to either inputs or outputs). The choice between these metrics benefited highly efficient units.[195]

MATS allowed for fuel conversion as one mechanism of compliance. As part of its MATS compliance, Alabama Power Company converted 10 generation units totalling 1.9 GW of capacity to natural gas around 2015.[196] Power plants could also use co-firing with other fuels to meet emission targets and reduce emissions of SO_2 and NO_x. For mercury-specific reporting, bituminous coal-fired units could choose to average emissions over either a 30- or 90-day period, depending on their chosen compliance standard.[197] They could also average emissions across power units in the same facility.[198] These are both examples of compliance flexibility provided through averaging of emissions.

As demonstrated in the description of emission control technologies, there are various options for type of control equipment to reduce acid gas and mercury emissions.

Good Neighbor Plan

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[193] One example is FirstEnergy, a power company in the Midwest, who projected compliance costs in the range of $3 billion, but actual costs were closer to $350 million. See Environmental Defense Fund, Meeting the Mercury and Air Toxics Standards for Power Plants: Greater Benefits, Lower Costs.

[194] Stephanie Sebor, Strategies for Compliance With Mercury and Air Toxics Standards, September 2014, p. 9.

[195] *Ibid.*, p. 8.

[196] EIA, Today in Energy: More than 100 coal-fired plants have been replaced or converted to natural gas since 2011, August 5, 2020.

[197] If units choose to comply with the 90-day averaging period, the emissions rate they must meet is more stringent. EPA, Building Flexibility with Accountability into Clean Air Programs, August 8, 2023.

[198] EPA, Building Flexibility with Accountability into Clean Air Programs, August 8, 2023.

The focal point of the GNP is the allowance trading program. Specifically, the GNP includes an allowance trading program for NO_x such that the affected power plants must surrender an allowance for each unit of emissions they produce (by either using their allocated emissions allowances or by purchasing from other companies). Prices of allowances for the ozone season fluctuate throughout the year, and create the opportunity for power plant owners to purchase and trade these credits based on their changing need for allowances throughout the season.[199]

The GNP was finalized in March 2023, with emissions limits that were put into effect starting in the 2023 ozone season. For the first compliance year, the state budget amounts for total allowances are set based on the assumption that power plants only need to run their currently installed emission control technologies.[200]

Other mechanisms to comply with GNP include coal-to-gas conversion (which is expected by the EPA in their modeling of reliability impacts),[201] reducing generation output, and co-firing with cleaner fuels.

Proposed 111(d) GHG Rule

EPA's proposed 111(d) GHG rule also provides many specific compliance pathways for existing power plants. The rule 111(d) pertains to existing plants, and there is a separate rule (111(b)) that affects new power plants. Different types of generation units would be presented with different pathways. We focus on the proposed rule 111(d) because emissions reduction requirements for existing plants is more likely to affect reliability in the near-term compared to requirements for new resources.

Existing Coal-Fired Units

[199] See Ohio, et al. (No. 23A349), Kinder Morgan, Inc., et al. (No. 23A350), American Forest & Paper Association, et al. (No. 23A351), Applicants v. United States Environmental Protection Agency, et al., Public Interest Respondents' Response in Opposition to Emergency Applications for Stay of Final Agency Action during Pendency of Petitions for Review, Appendix, Declaration of Metin Celebi, Ph.D., October 30, 2023, pp. 1-7; EPA, EPA's Proposed 'Good Neighbor' Plan to Address Ozone Pollution – Overview, March 2022, pp. 1-2.

[200] Carrie Jenks and Hannah Oakes Dobie, 2023 Good Neighbor Plan, Environmental & Energy Law Program, March 21, 2023.

[201] EPA, Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, May 2023, p. 5-15.

Existing coal-fired units would have four potential pathways for compliance in the proposed regulation. The first is to commit to installing carbon capture and storage (an emission control technology) to remove 90% of emissions by 2030, with the opportunity to continue operations indefinitely.[202] The second option is to commit to retire before 2040, and co-fire with gas (at 40% gas) starting in 2030.[203] The final two options would require no co-firing or carbon capture, but are available to units that have elected to limit average output to 20% of maximum capacity and have committed to retire before 2035, or to units that retire before 2032.[204]

Existing Gas-Fired Units

Existing gas-fired units would have a choice between two options. They could choose to operate at normal capacity with 90% emissions reductions through carbon capture and storage starting in 2035, or they can choose to co-fire with other fuels, by co-firing with 30% clean hydrogen in 2032 and 96% clean hydrogen in 2038. It should be noted that the standards for existing gas-fired units only applies to those with capacity greater than 300 MW and operating at more than 50% capacity factor. In other words, smaller and infrequently dispatched gas-fired units would not be required to reduce their GHG emissions under the proposed rule.

Similar to other federal regulations, the proposed rule 111(d) also allows states to propose their own implementation plans. The regulation permits state allowance trading programs as an option for states to include in their implementation plans.

C. Advance notice to implement compliance plans

Recent environmental regulations (such as the Good Neighbor Plan and the proposed GHG rule) include multi-year periods between finalization of rules and their associated compliance start dates in order to provide power plant owners and grid operators time to plan for and implement their capital-intensive compliance solutions (such as retrofitting a plant with a new emissions control equipment). The regulations change the economics of operation for the affected power plants and when faced with changing economic conditions, power plant owners must re-evaluate the economic feasibility of different compliance options. When provided ample time to consider

[202] Environmental & Energy Law Program, EPA proposes new rule to combat climate changing pollution from power plants (Timelines), May 5, 2023.

[203] Environmental & Energy Law Program, EPA proposes new rule to combat climate changing pollution from power plants (Timelines), May 5, 2023.

[204] Environmental & Energy Law Program, EPA proposes new rule to combat climate changing pollution from power plants (Timelines), May 5, 2023.

different compliance strategies before compliance is required, they can implement the economic option in an orderly fashion without causing adverse impacts on system reliability. While the most economic outcome may be retirement or generation reductions for some power plants, a long lead time between the issuance of the regulation and the compliance deadline allows for continued operation while system operators plan around these changes to the generation mix. In fact, the option under the proposed 111(d) GHG rule for a coal plant owner to identify the retirement year (e.g., by 2035 under one of the four compliance options) provides additional certainty and lead time to the system planners and operators to plan for bringing the appropriate amount of replacement resources on a timely basis.

Moreover, recent regulations typically have different compliance dates associated with progressive levels of compliance. In some cases, escalating stages of compliance standards allow for even more time before major equipment investments are required.

Some examples of this timing in recent regulations include the following:

Clean Air Act Section 111(d) GHG Rule: One example is EPA's recent GHG regulation that was proposed on May 11, 2023. The regulation is aimed at decreasing GHG emissions from existing power plants. With compliance requirements starting in 2030, the rule gives ample lead time to prepare compliance options.[205] Existing combustion turbine power plants that are considered "large and frequently used" are subject to standards that provide two options for compliance that go into effect in 2032 or in 2035.[206] Coal plants are given four options that have varying emissions standards to achieve by 2030 depending on the committed year of retirement from 2032 to 2040.[207] These requirements will prompt owners and operators to examine the economics of the continued operation of their existing units and decide whether to invest in pollution controls or plan for retirement before 2035, facilitating a more orderly transition to a cleaner generation mix.

Good Neighbor Plan: Another example is the GNP that was proposed in March 2022 to address the Clean Air Act "good neighbor" requirements of the 2015 National Ambient Air Quality Standards for ozone.[208] This proposal proceeded through the standard comment period and was

[205] Environmental & Energy Law Program, EPA proposes new rule to combat climate changing pollution from power plants (Timelines), May 5, 2023.

[206] Environmental & Energy Law Program, EPA proposes new rule to combat climate changing pollution from power plants (Timelines), May 5, 2023.

[207] Environmental & Energy Law Program, EPA proposes new rule to combat climate changing pollution from power plants (Timelines), May 5, 2023.

[208] EPA, EPA Proposes 'Good Neighbor' Plan to Cut Smog Across Much of the United States, March 11, 2022.

finalized on March 15, 2023.[209] Initial compliance is required for the 2023 ozone season for NO_x emission controls, but the standards for 2023 can be achieved by operating the existing control equipment at the plants.[210] Further reductions are scheduled in phases, and later required reductions in emissions are based on installing state-of-the-art control equipment such as SCRs.[211]

D. Emergency exemptions provide a last resort option

Emergency exemptions are not mechanisms that power plants or grid operators can plan on, but as plants retire and system operators work to ensure reliability in the grid, there is the potential for regulators to provide exemptions to generation units in order to ensure generation capacity can meet peak demand. Under both state and federal regulations, these emergency measures can be based on forecasted need well into the future.

The EPA evaluates the reasons for non-compliance with standards, such as those needed for emergency grid operations, on a case-by-case basis. This review process allows for consideration of impacts to electrical reliability, timing of the violation, and extenuating circumstances.

The interaction of government agencies with ISOs/RTOs and other grid operators when determining emergency exemptions exists as part of the Federal Power Act (FPA) and regulations for the DOE. Specifically, FPA sections 202(c) and 215(b) allow FERC and the Secretary of Energy to declare an emergency to the electric grid and take measures to alleviate the emergency.[212] FERC, specifically, has the power to grant exemptions for environmental law or regulation, but both are required to consult each other in the event of an emergency declaration.[213] Separately, Section 205, Subpart W, of Department of Energy Regulations also specifies that in the event of an emergency, measures may be issued that "protect or restore the reliability of critical electric

209 EPA, Good Neighbor Plan for 2015 Ozone NAAQS.

210 EPA, EPA's 'Good Neighbor' Plan Cuts Ozone Pollution – Overview Fact Sheet, p. 1.

211 EPA, EPA's 'Good Neighbor' Plan Cuts Ozone Pollution – Overview Fact Sheet, p. 1.

212 U.S. Government Publishing Office (GPO), 16 U.S.C. § 824a, 2022, Interconnection and coordination of facilities; emergencies; transmission to foreign countries.

213 GPO, 16 U.S.C. § 824a, 2022, Interconnection and coordination of facilities; emergencies; transmission to foreign countries.

infrastructure."[214] An emergency designation can affect any electric reliability organization, regional entity, or operator of critical electric infrastructure.[215]

During Winter Storm Uri, the Secretary of Energy issued exemptions to remove many air pollutant restrictions in order to meet demand during the cold spell.[216] Specifically, the Secretary of Energy relaxed standards for SO2, NOx, mercury, carbon monoxide, and wastewater effluent in response to the winter storm. As reasoning for providing the emergency exemption for ERCOT, the Acting Secretary specifically cited "the emergency nature of the expected load stress, [and] the responsibility of ERCOT to identify and dispatch generation necessary to best meet the emergency and serve the public."[217]

PJM requested the emergency exemption pathway to ensure reliability during Winter Storm Elliott in 2022. On December 24th, 2022, PJM requested an issuance of an emergency for electric reliability purposes.[218] PJM expressed that there was the potential for generators to be unable to produce their maximum output during peak hours due to state and federal regulations, and requested the ability to instruct operators to run generators past the point of regulatory limits in order to meet demand.[219] As part of the request for emergency issuance, PJM stated that it expected that amounts of SO_2, NOx, mercury, and carbon monoxide would exceed otherwise allowable limits.[220] The Secretary of Energy responded with an emergency issuance and stated that emission restricted generators would be "allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert."[221]

Emergency exemptions are also included in rule 111(d) for regulating GHG emissions.[222] The regulation specifies that "electricity sold during hours of operation when a unit is called upon to

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214 GPO, 10 C.F.R. § 205.381, 2022.

215 GPO, 16 U.S.C. § 824a, 2022, Interconnection and coordination of facilities; emergencies; transmission to foreign countries.

216 DOE, Federal Register, April 7, 2021, Vol. 86, No. 65, p. 2.

217 DOE, Federal Register, April 7, 2021, Vol. 86, No. 65, p. 2.

218 Manu Asthana, Request for Emergency Order Under Section 202(c) of the Federal Power Act, PJM, December 24, 2022.

219 *Ibid.*

220 *Ibid.*

221 Kathleen B. Hogan, Order No. 202-22-4, DOE, December 24, 2022, p. 4.

222 EPA, 88 FR § 33240, May 23, 2023, New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.

operate due to a system emergency is not counted toward the percentage electric sales subcategorized threshold."[223] Based on the current language the definition of a system emergency would be defined by the grid operator based on the need to "maintain grid reliability."[224]

Since 2020, there have been 11 emergency orders issued by the Department of Energy to relax environmental compliance requirements resulting from winter storms, hurricanes, wildfires and other natural disasters.[225]

VI. Conclusions

Fundamental change is ongoing in the electricity supply mix and electrification of energy use. Technologies and processes to support reliability in the new grid have advanced rapidly, from batteries to grid-forming inverters to enhanced operating and planning practices. Grid operators and their regulators can ensure reliability through this transition by using their existing tools, enhancing them, developing new mechanisms where needed, and incorporating new technologies. To avoid forcing a choice between reliability and the changing demands on the grid, grid operators must make these adaptations quickly enough to keep pace with the changing grid.

Environmental regulations only one of many drivers of evolving needs to maintain electric grid reliability, and therefore can play only a limited role in moderating the pace of change. Economic factors, customer preferences, and state and federal clean energy policies have been and will continue to be major forces behind the transition of the supply mix from fossil-fuel generation to lower emitting resources. These trends will continue to drive industry change with or without new federal environmental regulations. While environmental regulations have also contributed to this transition by making it more costly to operate for some emission-intensive generation plants (such as uncontrolled coal-fired plants), the decisions on whether to reduce generation output or to retire generation plants have always been economic decisions made by plant owners or their state regulators based on a confluence of factors, any one of which may well be decisive on its own.

[223] *Ibid.*

[224] *Ibid.*

[225] DOE: Office of Cybersecurity, Energy Security, and Emergency Response, "DOE's Use of Federal Power Act Emergency Authority," accessed November 28, 2023.

The timelines of grid evolution, grid operator adaptations, and compliance for new environmental regulations combine in ways that are specific to each context. In certain cases, grid reliability can benefit from existing compliance flexibilities in environmental regulations, for example where grid operators have been delayed in adapting their tools, where demand has grown especially quickly, where transmission and grid-enhancing technology are particularly slow to build, or where wind and solar costs are very low and therefore competition with conventional generation markedly steep. To accommodate such cases, new environmental regulations are implemented with various compliance flexibilities that avoid sacrificing reliability. These allow plant owners, state regulators and system planners to develop economical compliance plans that appropriately fit with the broader reliability context of grid evolution.

Appendix A: Past and Future Changes in the Electricity Industry

A. Recent past industry changes

The electric power grid is expected to undergo a major transition in the next two decades, continuing trends that have brought about a shift from fossil fuel-based systems of energy production to increasing penetration of renewable energy and storage resources complemented by flexible electricity demand. Each trend in this transition is driven by distinct factors and results in different reliability effects. To understand the reliability effects of the changing grid and how they might be affected by various regulations, it is important to recognize the nature of the changes and why they are happening.

The electric power grid has been evolving over the last decade in several respects:

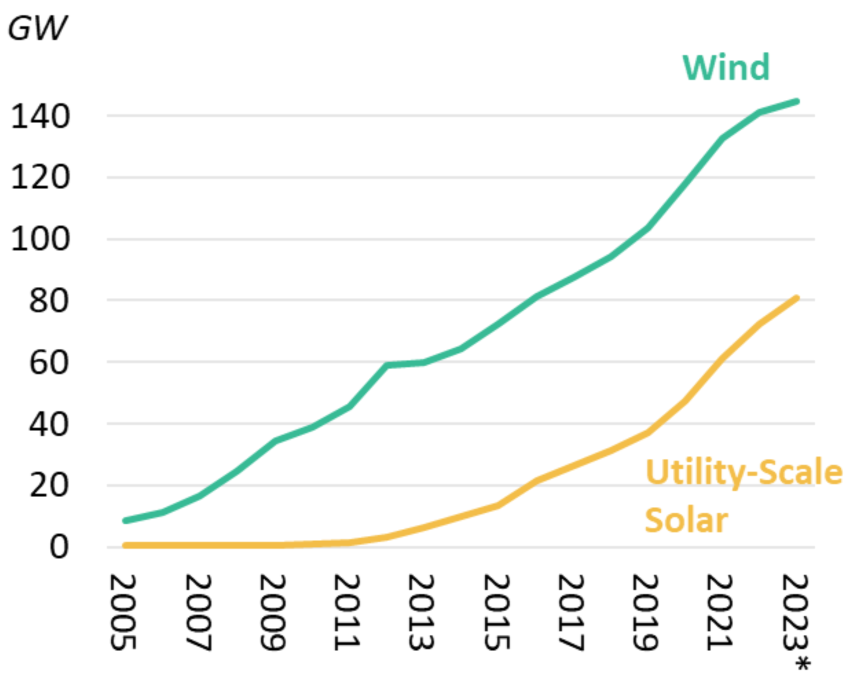
- Cost declines and rapid expansion of wind, solar, and gas generation
- Low load growth due to increasing population and growth in certain subsectors of the economy that has been largely offset due to macroeconomic shifts, energy efficiency measures, and efficiency improvements in end-use technologies
- Retirement of coal-fired generation facing competition from cost competitive renewables and gas, low energy prices, and new environmental regulations
- Expansion of regional wholesale markets, especially in the West, as utilities sought to integrate renewables and reap efficiency and cost savings
- Increased impact of extreme weather events, especially cold weather, due in part to a changing resource mix that is more reliant on gas that has been susceptible to cold weather forced outages and increasing winter electricity demand

1. Increase in wind and solar generation

The last two decades have seen substantial growth in solar and land-based wind generation capacity in the U.S. As shown in Figure 13, onshore wind generation capacity grew at an average rate of 19% per year between 2005 and 2022, reaching 141 GW by the end of 2022. Meanwhile, utility-scale solar has grown at an average of 39% per year over this same timeframe, reaching

72 GW by the end of 2022.[226] As of 2022, 14% of total U.S. electricity generation output came from solar and wind and an additional 26% came from other clean energy resources like nuclear and hydro.[227]

FIGURE 13: CUMULATIVE WIND AND SOLAR INSTALLED CAPACITY IN THE U.S.



Notes and Sources: *Capacity shown as of August 2023. EIA, Monthly Energy Review, 2023, Table 7.7b.

Drivers of past increase in wind and solar generation

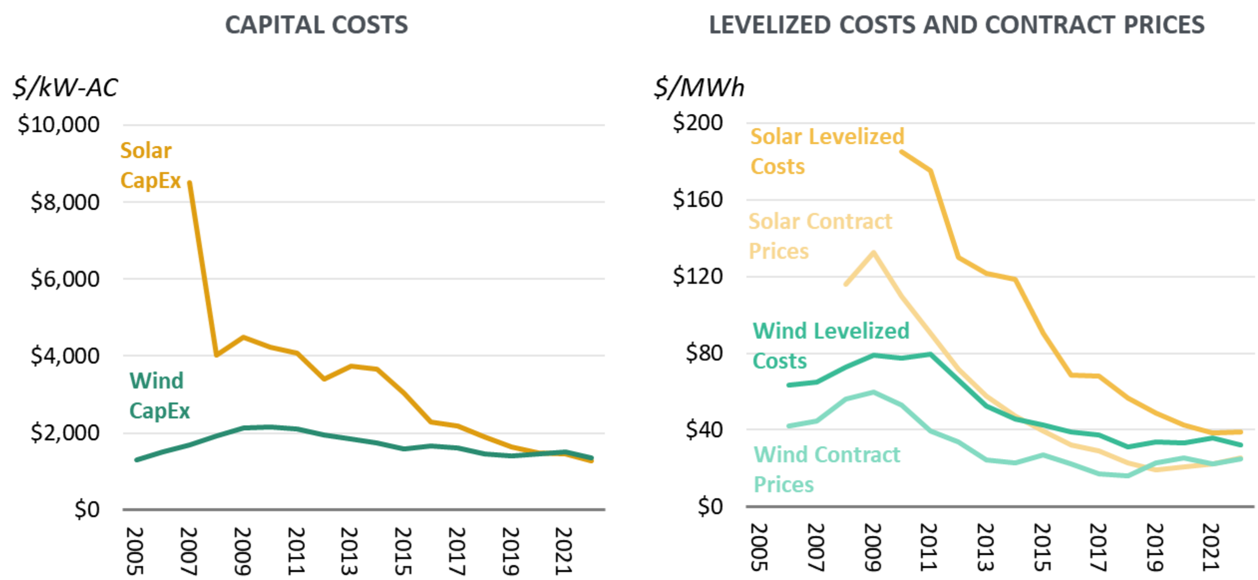
This substantial growth in wind and solar capacity has been spurred mainly by rapid cost declines in wind and solar technology, improvements in performance, consumer preferences, and beneficial clean energy policies such as state Renewable Portfolio Standards (RPS), and the federal investment tax credit and production tax credit incentives. Recently there has been an uptick in battery storage capacity that is expected to undergo similar growth.

[226] Excludes distributed solar and concentrated solar plants; LBNL, "Utility-Scale Solar 2023 Edition," 2023; DOE, "Land-Based Wind Report," 2023, accessed November 28, 2023.

[227] EIA, Monthly Energy Review, 2023, Table 7.2b.

Technology capital costs, contract prices, and levelized cost data for wind and solar all show substantial reductions over the past decade, as shown in Figure 14.[228] Capital costs for solar PV have decreased by 70%, from $4,232/kW in 2010 to $1,270/kW in 2022, driven by declining hardware costs and economies of scale.[229] This decline in solar capital costs coupled with improvements in production efficiency, have decreased levelized costs by 79% between 2010-2022.[230] Contract prices, which include the impacts of tax incentives, are lower than levelized costs and have decreased by 77% for solar between 2010-2022 in nominal terms.[231] Capital costs for wind have decreased by 37% in nominal terms from $2,155/kW in 2010 to $1,367/kW in 2022, while levelized costs of wind have declined by 59% and contract prices have declined by 52% over the same time period on a nominal basis.[232]

FIGURE 14: HISTORICAL SOLAR AND WIND CAPITAL COSTS, LEVELIZED COSTS, AND CONTRACT PRICES



Notes and Sources: Values all correspond to new wind and solar generators. Levelized costs and contract prices include both capital costs and ongoing operating costs. Levelized costs are a hypothetical fixed cost-per-MWh for a new wind or solar generator (not accounting for state and federal tax credits). Contract prices are average market-based contract prices from surveys. Dollars are expressed in nominal terms; LBNL, Utility-Scale Solar 2023 Edition, October 2023; DOE, Land-Based Wind Report, 2023.

228 The Levelized Cost of Energy (LCOE) measures the per unit value of the total cost of building, operating, and maintaining a power plant over an assumed financial life. LCOE represents the average revenue required to recover costs and investment returns associated with a power plant.

229 Nominal dollar values. LBNL, "Utility-Scale Solar 2023 Edition Data File," 2023, accessed December 4, 2023.

230 *Ibid.*

231 *Ibid.*

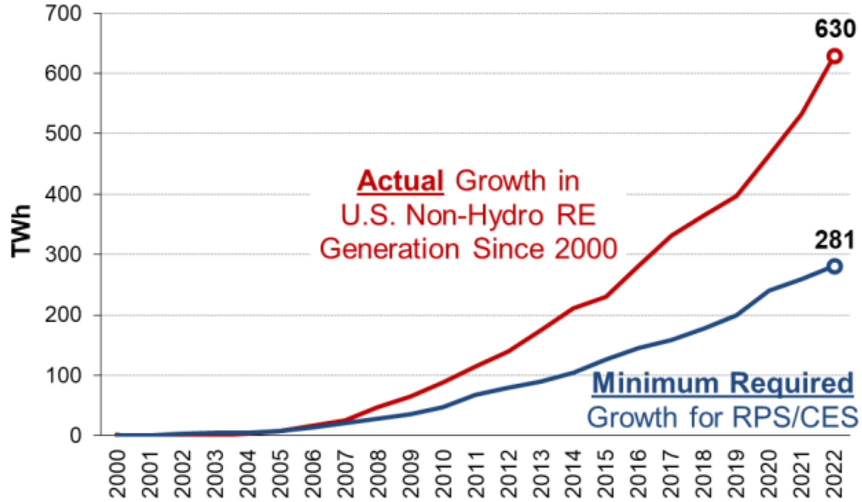
232 DOE, "Land-Based Wind Market Report: 2023 Data File," 2023, accessed December 4, 2023.

Customer preferences for clean energy have directly motivated development of significant wind and solar through long-term corporate procurements (which represented approximately 17% of new wind and solar built in 2022); Community Choice Aggregations, whereby a municipal government procures supply (generally clean) on behalf of its citizens; and other voluntary renewable credits, for example for residential customers in retail choice programs in applicable states.[233]

With increasing awareness of adverse impacts of climate change and interest in supporting regional energy production industries, state governments enacted clean energy policies to require more renewables to contribute to their supply mix through renewable portfolio standards. While state policies have partly contributed this renewable growth, favorable cost factors have played an important role in the increase in wind and solar capacity as well. Figure 15 illustrates this point, showing how overall renewable growth has outpaced the minimum renewable energy required to meet state targets in the last decade. Some states have required certain amounts of solar capacity to be procured. In a few states today, similar procurement targets are being announced for battery storage, which is expected to contribute to a rapid increase in deployment of these resources in the future.

[233] Municipal procurement data from NREL, Status and Trends in the Voluntary Market (2022 Data), September 20, 2023. Installed capacity additions with corporate buyers from Clean Energy Power, 2022 Corporate Buyers Report, January 2023, p. 41; Total increase in wind and solar capacity in 2022 from EIA, Monthly Energy Review, 2023, Table 7.7b; EPA, "Community Choice Aggregation," October 27, 2023, accessed December 4, 2023.

FIGURE 15: RENEWABLE DEPLOYMENT TO MEET STATE RPS GOALS VS ACTUAL DEPLOYMENT



Notes: Minimum Required Growth for RPS/CES excludes compliance contributions from pre-2000 vintage facilities, and from hydro, municipal solid waste, nuclear, and other non-RE technologies. This comparison focuses on non-hydro RE, because RPS rules typically allow only limited forms of hydro for compliance.

Notes and Sources: "RE" stands for renewable energy, and "CES" stands for Clean Electricity Standards; Galen Barbose, U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status. Update, June 2023.

In addition, the federal government has been providing tax incentives (namely, the ITC and PTC) to improve the financial attractiveness of wind and solar generation, most recently through the Inflation Reduction Act (IRA) of 2022. Even before the recent extension of the tax credits, both wind and solar in the most advantageous locations had been estimated to be lower cost than the most efficient new gas generators on a levelized all-in cost of energy basis.[234] The effect of the tax credits has therefore been to make the all-in cost of new-build wind and solar less than that of the most efficient new gas generators in many parts of the country, and in the best locations, less expensive per MWh of energy output than the estimated fuel + maintenance cost of operating an existing gas combined-cycle plant.

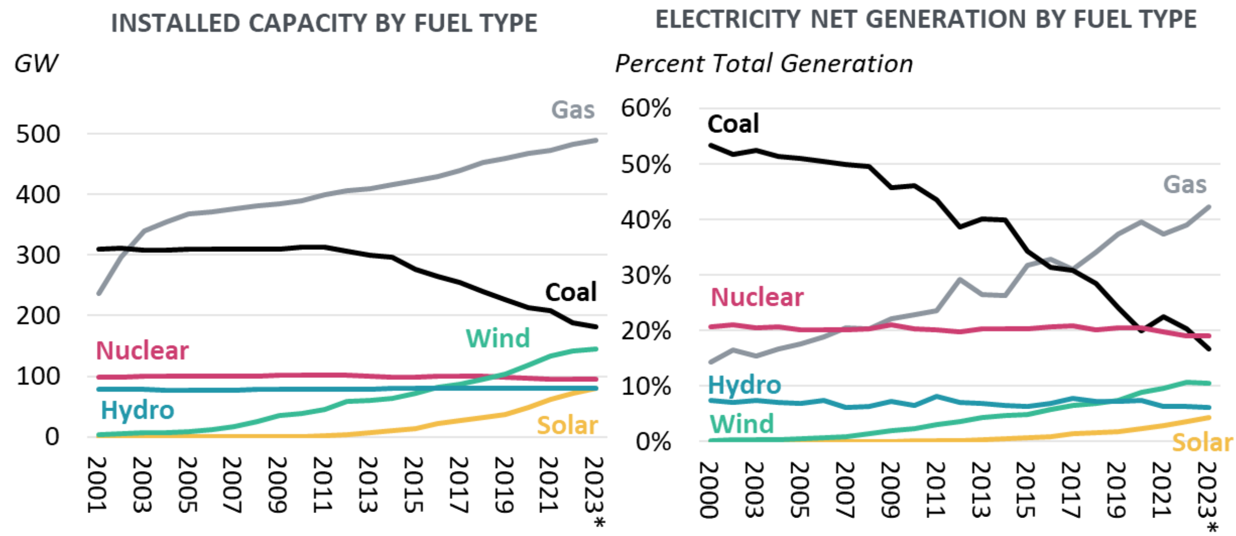
2. Increase in natural gas generation

Natural gas generation capacity has been growing steadily in the US, increasing by 121 GW between 2005 – 2023.[235] In 2003, natural gas overtook coal as the technology with the most generating capacity (MW) while it surpassed coal in net energy production (MWh) in 2016, as shown in Figure 16 below.

[234] Lazard, Levelized Cost of Energy Analysis—Version 16.0, April 2023.

[235] 2023 total represents capacity growth as of August 2023, see EIA, Monthly Energy Review, 2023, Table 7.7b.

FIGURE 16: ELECTRICITY CAPACITY AND GENERATION BY FUEL TYPE



Notes and Sources: 2023 data represents installed capacity and net generation from January through August 2023, installed capacity equal to installed summer capacity, excludes capacity and generation from oil, storage, geothermal, and biomass sources; EIA, Monthly Energy Review, 2023, Table 7.2b, Table 7.7b.

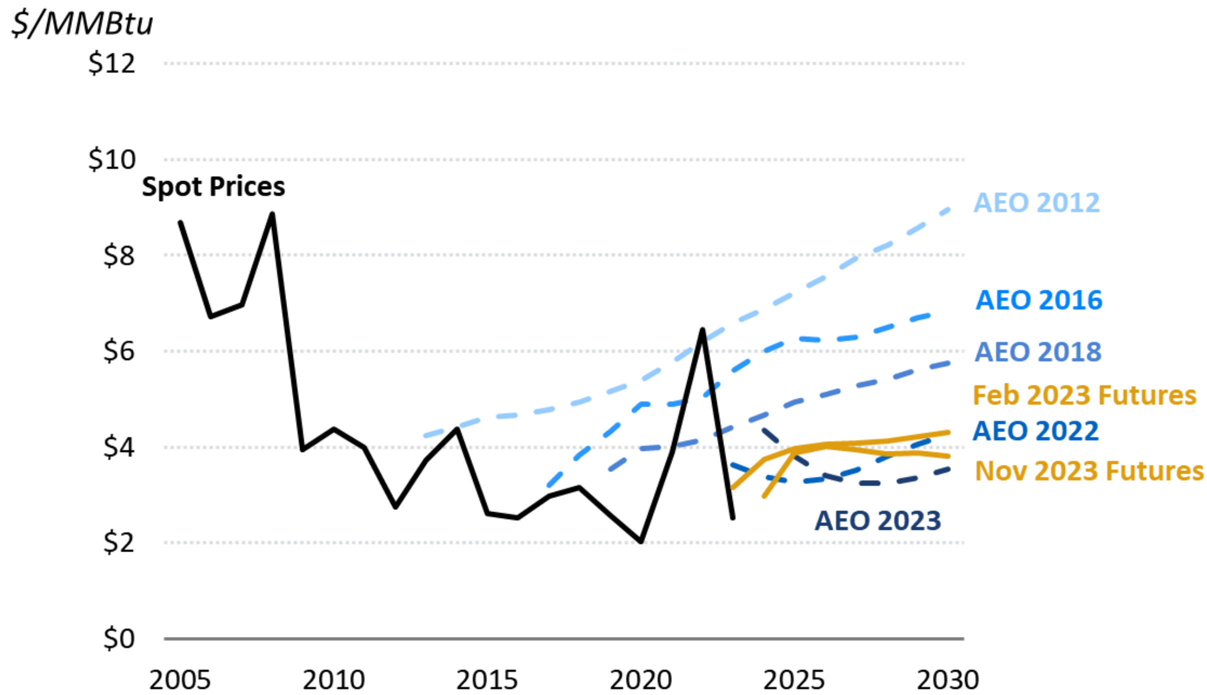
Drivers of past increase in natural gas generation

The expansion of natural gas generation has been driven predominately by sustained declines in natural gas prices and increases in generation efficiency in natural gas turbines, reduction in siting and construction timelines of gas-fired generation, and more flexible attributes and fewer CO_2 emissions compared to coal-fired plants.

In the period between 2005 and 2010, natural gas prices in the U.S. declined dramatically with more moderate declines continuing through 2020, despite many early projections of price increases as demonstrated in Figure 17.[236] More recent projections of gas prices indicate flat or decreasing price expectations.

[236] Note that gas price forecasts often lag behind spot price reductions, but they also exhibit a downward trend as the impacts of shale gas on the market became clearer.

FIGURE 17: HISTORICAL AND FORECASTED HENRY HUB NATURAL GAS PRICES



Notes and Sources: EIA, Natural Gas, Henry Hub Natural Gas Spot Price, accessed December 5, 2023; EIA, Annual Energy Outlook 2012, June 2012, Table: Natural Gas Supply, Disposition, and Prices; EIA, Annual Energy Outlook 2016, August 2016, Table: Natural Gas Supply, Disposition, and Prices; EIA, Annual Energy Outlook 2018, February 6, 2018, Table: Natural Gas Supply, Disposition, and Prices; EIA, Annual Energy Outlook 2022, March 3, 2022, Table 13; EIA, Annual Energy Outlook 2023, March 16, 2023, Table 13; S&P Global Market Intelligence LLC., Natural Gas Forwards & Futures.

The "shale gas boom" was the biggest driver for the decline in gas prices post 2008 due to advancements in fracturing and drilling technologies. This increased estimated national gas reserves by 35% and subsequently reduced prices from a peak of $9/MMBtu in 2005 to around $2/MMBtu in 2020.[237] In 2021 and 2022, there was a spike in natural gas spot prices due to Russia's invasion of Ukraine, increased liquefied natural gas exports, and fast recovery from the COVID-19 pandemic which increased demand. However, prices have significantly abated, and are expected to revert closer to the pre-2021 mean in the medium to long term, as evidenced by industry-wide expectations of lower gas prices both in projections and futures.

[237] Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023, p. 10; EIA, Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States, June 2013, p. 3.

The most efficient modern natural gas generators can reach efficiencies of 60%, substantially greater than the typical efficiency of about 30% for coal units.[238] From the 1980s to 2000, construction costs and timelines for natural gas fired plants declined by 50% with current construction timelines as little as 2 years for gas generators.[239] Natural gas fired generators also have shorter start up times and higher ramp rates, which have contributed to the increased economic attractiveness of natural gas plants compared to coal plants.

Gas combustion has relatively lower emissions than coal, an advantage for gas generation especially as stricter environmental regulations emerged over the last decade.

3. Low electricity demand growth

Growth in demand for electricity has been fairly flat over the last two decades. Compared to the historical electricity demand growth rate of 2.4% per year between 1980 and 2000, the average national demand growth rate between 2000 and 2023 was only 0.7% per year, as shown in

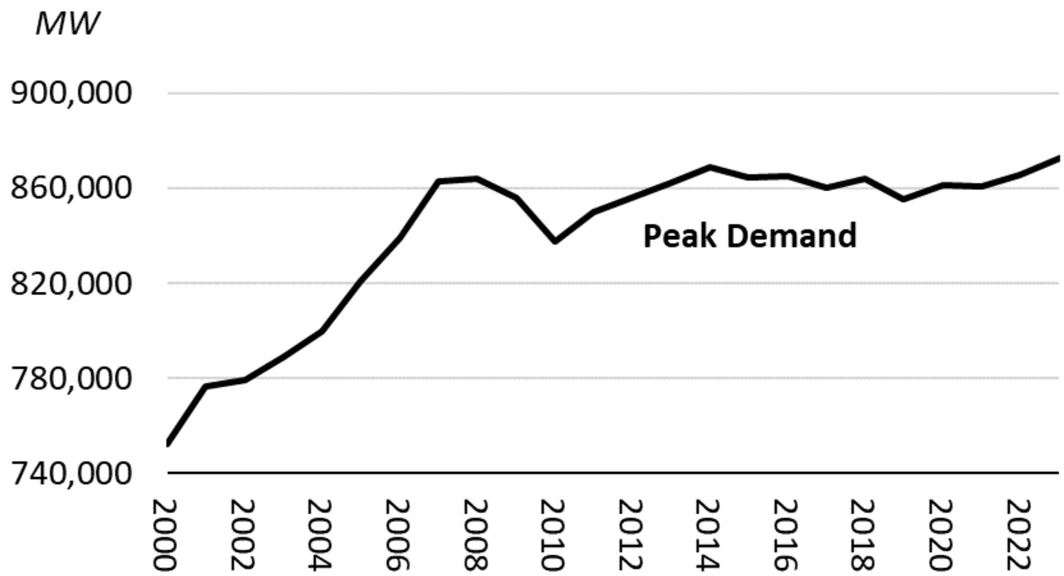
Figure 18.[240]

[238] Here, "efficiency" of a power plant is defined as the ratio of the electrical energy produced to the total energy content of the fuel required to produce it. NREL, "Natural Gas Plants," 2023, accessed November 29, 2023.

[239] Sargent & Lundy, Capital Cost Study Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, February 5, 2020.

[240] Growth prior to 2000 calculated from NERC data on historical peak load, while growth between 2000 and 2022 calculated from NERC near-term forecasts of peak load. See NERC, 1992 Long-Term Reliability Assessment, September 1992, p. 8; NERC, 2000 Long-Term Reliability Assessment, October 2000, p. 7; NERC, 2003 Long-Term Reliability Assessment, December 2003, p. 14; NERC, NERC, 2023 Long-Term Reliability Assessment, December 2023, Supplemental Charts and Graphs, Table F.

FIGURE 18: HISTORICAL U.S. PEAK ELECTRICITY DEMAND



Notes and Sources: Historical near-term forecasts of peak load; NERC, 2023 Long-Term Reliability Assessment, December 2023, Supplemental Charts and Graphs, Table F.

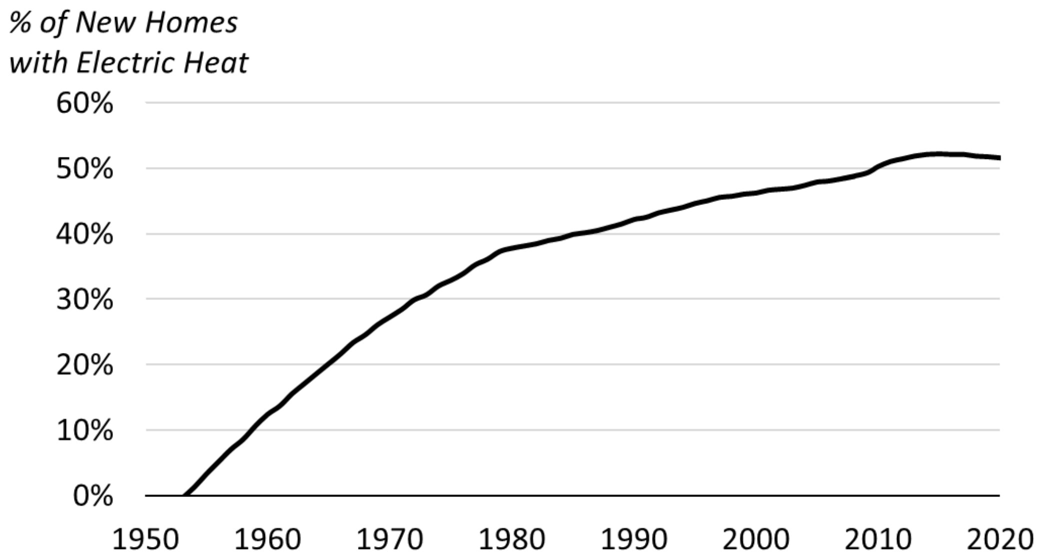
However, in the more recent past, some pockets of the country have seen an uptick in electricity demand due to new sources of demand such as data centers. Consumption from data centers was 1.8% of all electricity demand in 2014, and data center electricity demand has increased by around 500% for some specific markets between 2013 and 2022. [241]

Heating electrification has been developing mostly based on economics without policy intervention for the past 70 years from only 1% of homes using electricity as their primary source of heat in 1950 to 40% of homes in 2020.[242] When considering new-built homes, over 50% have primarily electric heat as of 2020 as shown in Figure 19.

[241] Arman Shehabi, et al., United States Data Center Energy Usage Report, LBNL, June 2016, p. ES-1; Jared Anderson, et al., POWER OF AI: Wild predictions of power demand from AI put industry on edge, S&P Global Commodity Insights, October 16, 2023.

[242] Lucas W. Davis, What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices, NBER Working Paper Series, October 2023, p. 2.

FIGURE 19: PERCENTAGE OF NEW U.S. HOMES HEATED WITH ELECTRICITY



Notes and Sources: Lucas W. Davis, What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices, NBER Working Paper Series, October 2023.

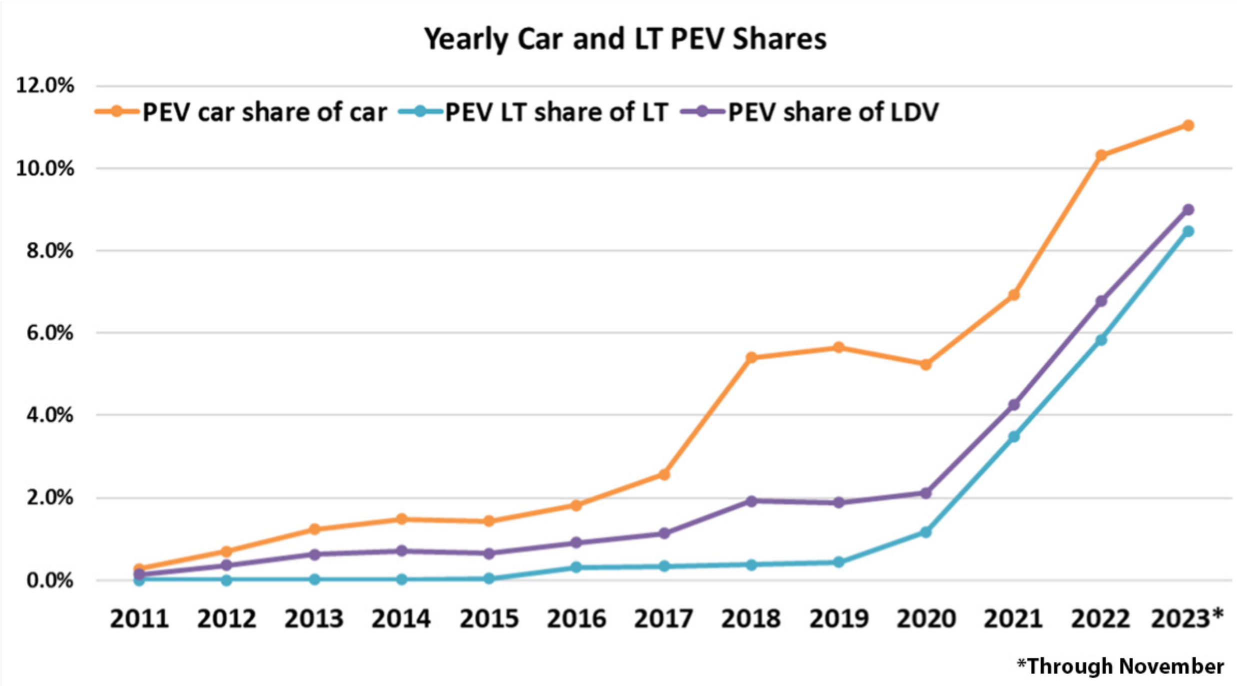
As states seek to decarbonize their economies, they have begun to pursue policies to encourage further electrification of heating and transportation. While increased demand driven by decarbonization policies so far has been slight, the trends in electrification are evident and will inevitably increase demand.[243] These decarbonization policies complement shifting consumer preferences and technological advancements, which will similarly advance the electrification of heating and transportation and contribute to increased demand.[244] As an example of these recent trends, sales of electric vehicles have rapidly increased in recent years and represent over 8% of all light-duty vehicles (LDV) sold in the U.S. in 2023, as shown in Figure 20.[245]

[243] For example, in California, which hosts the majority of electric vehicles in the U.S., electric vehicle charging is forecasted to grow from less than 1% of peak load in 2023 to 5% in 2035. See California Energy Commission, "California Energy Demand Update, 2022-2035: CED 2022 Peak Forecast – IOU Planning Areas," accessed December 4, 2023.

[244] For example, see Connor R. Forsythe, et al., Technology advancement is driving electric vehicle adoption, Georgia Institute of Technology, May 30, 2023.

[245] "Light-duty vehicles" includes cars and light trucks and "electric vehicles" include battery electric and plug-in hybrid vehicles; Argonne National Laboratory, "Light Duty Electric Drive Vehicles Monthly Sales Update," 2023, accessed November 29, 2023.

FIGURE 20: ELECTRIC VEHICLES SALES SHARE OF TOTAL U.S. LIGHT-DUTY VEHICLES



Notes and Sources: "PEV" stands for plug-in electric vehicles, "LT" stands for light truck, "LDV" stands for light-duty vehicle; Argonne National Laboratory, "Light Duty Electric Drive Vehicles Monthly Sales Update," 2023, accessed December 14, 2023.

Drivers of past low electricity growth

Energy efficiency technologies have had a major impact on demand, driving much of the lower rate of demand growth observed over the last ten years. For example, consider that lighting represents 16% of demand in 2017.[246] The LED light bulb was commercialized and widely adopted in the 2000s, and uses 90% less energy than the equivalent incandescent bulb.[247] Motors power air conditioners, refrigerators, pool pumps, and much industrial demand. Industrial and commercial demand from motors alone accounted for 29% of electricity demand in 2018.[248] New inverter-based variable frequency motor drives improve motor efficiency by as much as 41%, depending on the application.[249]

246 DOE, Energy Savings Forecast of Solid State Lighting in General Illumination Applications, December 2019.

247 DOE, Lighting Choices to Save You Money, accessed November 28, 2023.

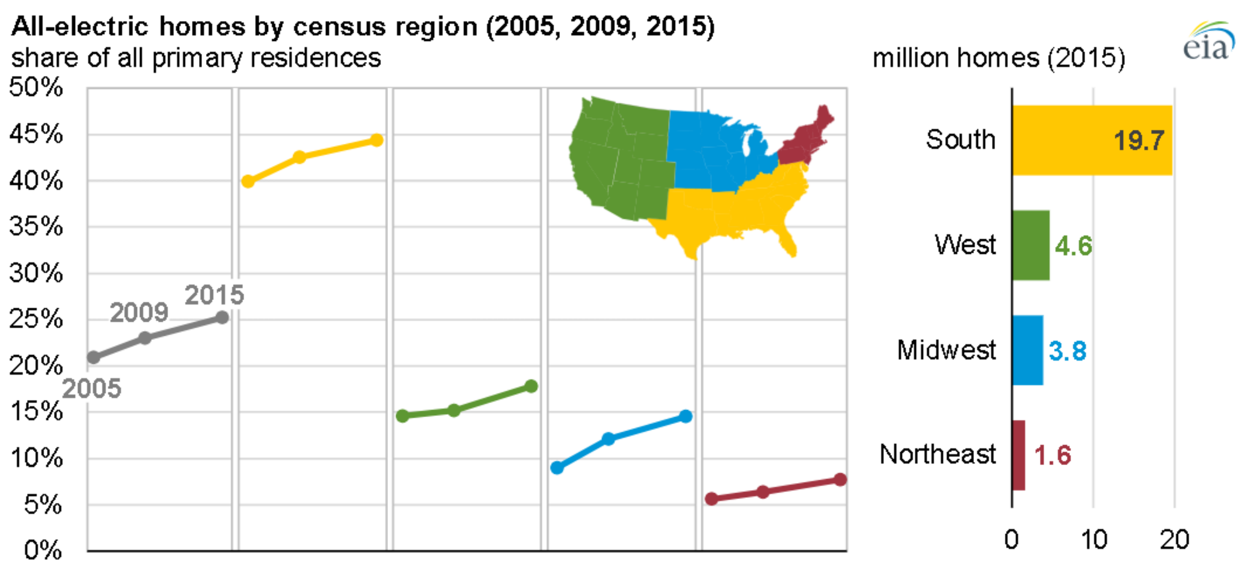
248 Prakash Rao, et al., U.S. Industrial and Commercial Motor System Market Assessment Report, Volume 1: Characteristics of the Installed Base, LBNL, January 2021, p.18.

249 For an air compressor operating at 40% Load Factor, see Prakash Rao, et al., U.S. Industrial and Commercial Motor System Market Assessment Report, Volume 3: Energy Saving Opportunity, LBNL, July 18, 2022, Equation 4.

Together, motors and lighting contribute to the majority of electricity demand and the gradual deployment of these significantly improved technologies together account for much of the absence of growth. The U.S. Department of Energy also added energy efficiency standards and continued other programs to promote highly efficient appliances (such as the EnergySTAR program.) The EnergySTAR program was responsible for reducing electricity demand by 520 TWh in 2020.[250]

Electrification of heating and other systems in residences has been increasing throughout the 2000s. Studies find that, over the decades, the increase in share of electric heating was largely driven by a significant decline in residential electricity prices that made electric heating cost-competitive with gas-based heating solutions.[251]

FIGURE 21: RESIDENTIAL ELECTRIFICATION TRENDS IN THE U.S.



Notes and Sources: Maggie Woodward, One in four homes is all electric, EIA, May 1, 2019.

4. Coal plant retirements

From 2005 to 2022, U.S. coal capacity decreased from 321 GW to 219 GW (a 32% reduction) while coal-fired generation output decreased more steeply from 1,886 TWh to 665 TWh, declining by

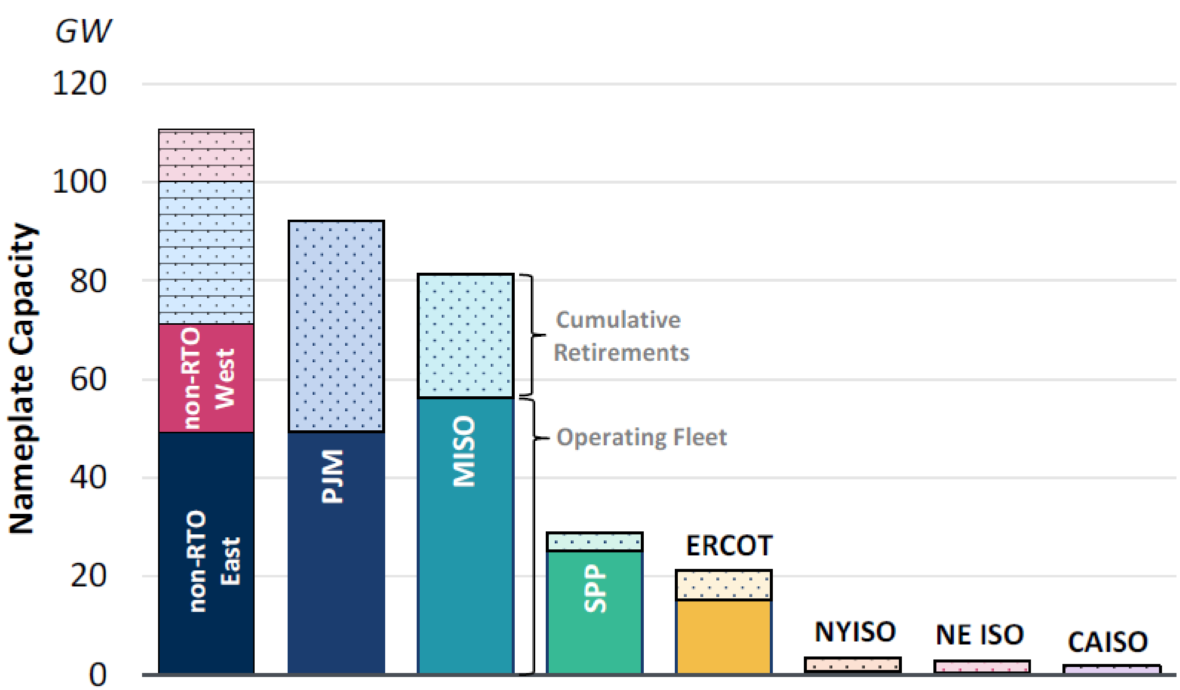
[250] EPA ENERGYSTAR, ENERGY STAR Impacts, accessed November 28, 2023.

[251] Luca Davis, et al., What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices, Energy Institute at Haas, October 2022.

65% across the same timespan.[252] The reduction in coal capacity corresponds to about 9% of total U.S. generation capacity.[253] An additional 68 GW of coal capacity has been announced for retirement by the end of this decade.[254] Meanwhile, there have been minimal (approximately 8.4 GW) coal additions after 2010, with no new utility coal generating units since 2014.[255]

As of December 2022, 219 GW of coal plants continue to operate, albeit with about half the energy output per generator today relative to 2005.[256] Figure 22 shows where cumulative coal retirements have taken place and where the remaining operating fleet are located per region.

FIGURE 22: TOTAL COAL RETIREMENTS AND CURRENT CAPACITY BY REGION (2005-2022)



Notes and Sources: Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

[252] As of December 2022; See Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

[253] As of December 2022; *Ibid.*

[254] As of December 2022; *Ibid.*

[255] Data from Energy Ventyx as of December 1, 2023.

[256] Data as of December 2022. The fleet-wide coal capacity factor, a measurement for how often power plants operate at full capacity, has decreased from 67% to 35% between 2005-2022. See Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

Drivers of past coal plant retirements

Coal plant retirements cannot be attributed to a single driver. Instead, several key factors have emerged as common contributors to past retirements: competition from cheaper renewable and gas resources; increasing operating costs of the aging coal fleet; low load growth that reduced the need for immediate replacement of retiring capacity with new resources; and capital costs of upgrades needed to comply with air and water quality standards set by new environmental regulations.

Competition from cheap renewables (which have zero marginal cost) and gas (driven by reductions in gas fuel prices and increased plant efficiencies) have resulted in higher cost coal plants being selected for dispatch in fewer hours compared to these other available resources. When cheaper resources are used to meet demand, this reduces wholesale market prices. The combination of lower wholesale market prices and coal plants being selected to run in fewer hours has resulted in lower energy market revenues for coal.

At the same time, the cost to operate these aging coal plants increased. The age of a coal plant is highly correlated to its operating and capital expenditures, with every additional year of operation adding a variable cost of $0.13/MWh and a capital expense of $0.04/MWh.[257] The U.S. coal fleet has an average age of 47.2 years, 20% older than the fleet average age in 2005.[258] Aging plants often experience more frequent cycling, an increase in equipment failures, and greater maintenance costs, hence reducing the economic attractiveness of retaining many coal plants.

Furthermore, relatively flat demand growth over the past two decades has meant that many utilities would not have to build new resources to meet load immediately after retiring a coal plant. This enabled utilities longer planning times before new generation would be needed and made retirement of coal an economically attractive and cost-effective approach in their fleets.

Recent federal environmental regulations to reduce pollution from power plants also impacted the economics of coal generators. Significant capital investments have been needed to control pollution at some coal plants, most of which were already facing decreasing economic advantages relative to alternative sources of power, therefore contributing to economic retirement of some coal plants. Those new EPA regulations included:

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[257] Metin Celebi, et al., [A Review of Coal-Fired Electricity Generation in the U.S.](), The Brattle Group, April 27, 2023.
[258] *Ibid.*

- The Mercury Air and Toxic Standards (MATS) in 2011 that set an emissions rate standard to reduce the emissions of mercury and other hazardous air pollutants at steam generating units with a capacity more than 25 MW.
- Coal Combustion Residuals (CCR), first regulated in 2014 and amended in 2020, under the Disposal of Coal Combustion Residuals from Electric Utilities rule, which established requirements for the handling of coal ash for safe disposal.
- Other prominent regulations that affected coal plants including the Regional Haze Rule (issued in 1999) and Cross-State Air Pollution Rule, (CSAPR) issued in 2011 and updated in 2016.

These environmental standards induced coal plant owners to compare the economics of investing in necessary environmental control equipment to keep plants online (and other compliance options, including purchase of emissions allowances), against the economics of retirement.

5. Growth of centralized regional wholesale markets

The Federal Energy Regulatory Commission (FERC) has encouraged the formation of interstate grid operators known as Independent System Operators and Regional Transmission Organizations (ISOs/RTOs), such as PJM, NYISO, and CAISO. The ISOs/RTOs pool generation and other resources across many member utilities to derive savings from economies of scale in operations and resource investments for long-term adequacy, and better transmission utilization. ISOs/RTOs naturally enhance reliability by providing more options to meet peak demand, more favorable demand profiles due to demand diversity across their footprints, and by reducing flexibility challenges.

Today approximately two thirds of national electricity demand is served in an ISO/RTO region.[259] Across all U.S. ISOs/RTOs, this has led to estimates of cost savings of over 12 billion dollars annually according to various studies.[260]

Utilities in most ISOs/RTOs manage resource adequacy either using capacity markets, wherein they must purchase capacity from a central market, or by meeting adequacy requirements

[259] FERC, "Electric Power Markets: National Overview", May 16, 2023, accessed December 5, 2023.

[260] John Tsoukalis, et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, The Brattle Group, April 2023, Table 8 and Table 9.

through self-supply or bilateral procurements, wherein they must demonstrate that their portfolio of resources meets the planning reserve margin standard set by the ISO/RTO.

While most of the growth of ISOs/RTOs occurred prior to the early 2010s, they continue to expand today (especially in the West).[261] A more recent development in similar centralized wholesale energy markets has been the creation of Energy Imbalance Markets (EIMs). EIMs jointly co-optimize the real-time output of generators from a number of utilities to meet aggregate load across a broad geographical area. CAISO and PacifiCorp initiated the Western EIM (WEIM) in 2014, which now covers 22 control areas across ten states in the West and part of Canada.[262] WEIM features 15-minute and 5-minute real-time dispatch of generation resources to meet energy imbalances, and gives operators visibility into neighboring balancing areas.[263] More recently, WEIM stakeholders have committed to adding day-ahead generator scheduling functionality through the Extended Day Ahead Market (EDAM) via CAISO.[264] Similarly, SPP began administering another EIM, the Western Energy Imbalance Service (WEIS), as of early 2021. WEIS extends real-time centralized dispatch of balancing services and demand to utilities outside of the SPP footprint.[265] SPP is also further developing day-ahead scheduling capabilities through the Markets+ effort.[266]

Finally, the Western Resource Adequacy Program (WRAP), slated to begin in 2025, is another example of increased regionalization of wholesale markets. The WRAP is a capacity-based resource adequacy focused market that will allow utilities in the West to pool capacity resources centrally and will result in reduced capacity procurement obligations for participants in part due to demand diversity across the footprint.[267] Figure 23 below is a summary of how these markets have expanded over time.

[261] SPP, SPP RTO will expand with commitments from western utilities, September 14, 2023.

[262] WEIM, "About: Western Energy Imbalance Market," 2023, accessed November 28, 2023.

[263] CAISO, Western Energy Imbalance Market Benefits Report Third Quarter 2023, October 31, 2023.

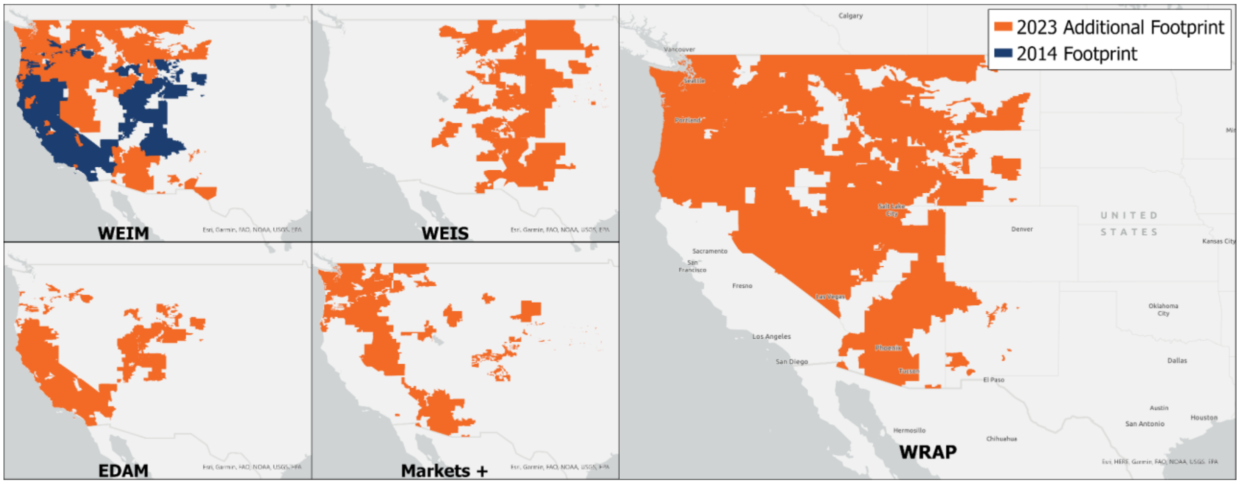
[264] CAISO, "Initiative: Extended day-ahead market," accessed November 30, 2023.

[265] SPP, "Western Energy Imbalance Service Market," accessed November 28, 2023.

[266] SPP, "Markets+," accessed November 30, 2023.

[267] As noted as one of the benefits of WRAP: "*Participants will have lower capacity procurement obligations than they would have if they were meeting the same capacity planning standard on their own*." See Western Power Pool (WPP), WPP Western Resource Adequacy Program Detailed Design: Executive Summary, March 2022.

FIGURE 23: GRID REGIONALIZATION PROGRAM FOOTPRINT: 2014 AND 2023



Notes and Sources: EIA, "Electric Retail Service Territories," December 9, 2022, accessed November 30, 2023; WEIM, "About: Active Participants," 2023, accessed November 30, 2023; CAISO, "EDAM: Extended Day Ahead Market," accessed November 29, 2023; SPP, "Western Energy Imbalance Service Market," 2023, accessed November 30, 2023; SPP, "Markets +," accessed November 30, 2023; Western Power Pool, "WRAP Area Map," November 21, 2022, accessed November 30, 2023.

The formation and expansion of centralized wholesale markets has been motivated by increased operating and planning efficiency, decreased costs, facilitation of higher levels of wind and solar integration, greater options to facilitate system reliability, and facilitation of customer choice and competition where appropriate.[268] Pooling of resources allows for an efficient – and therefore cost-effective – flow of energy to where it is needed within the market footprint, with pricing that reflects the marginal cost of deploying resources to serve demand. Regional markets are also better equipped to facilitate and reliably manage greater amounts of variable renewable generation, given their access to an extensive set of generators and well-defined day-ahead scheduling procedures.

6. Rising impact of extreme weather events

The impact of both extreme hot and extreme cold weather events has been increasing.[269] FERC has stated that:

[268] John Tsoukalis, et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, The Brattle Group, April 2023.

[269] NERC, 2023 State of Reliability Technical Assessment, June 2023.

> *"these events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."*[270]

Meanwhile, NERC states that:

> *"The reliability of conventional generation is significantly challenged by more frequent extreme weather, high demand conditions, and a changing resource mix, resulting in higher overall outage rates and surpassing transmission in their contribution to major load loss events. While the reliability of conventional generation has remained stable during normal operating conditions, the increased intensity and frequency of extreme weather events has contributed to a gradual rise in the conventional generation forced outage rate in recent years."*[271]

According to NERC and others, heat-related extreme weather events, such as the 2021 wildfires in California, the heat waves in California and Western Interconnect in 2020 and 2022, and the Western drought over the last two decades, have been increasing in frequency.[272] Extremely high air temperatures tend to increase the demand for electricity through increased used of cooling equipment, while at the same time decreasing the maximum output capabilities of some types of fossil fuel plants. Extreme heat above 110 degrees Fahrenheit can also impact the power capability of inverters.[273] Long droughts reduce the availability of water for hydroelectric plants

[270] DOE, FERC, 183 FERC ¶ 61,191, June 15, 2023, Transmission System Planning Performance Requirements for Extreme Weather, p. 5.

[271] NERC, 2023 State of Reliability Technical Assessment, June 2023, p. 3.

[272] NERC, 2023 State of Reliability Technical Assessment, June 2023, p. 8; Marco Turco, et al., Anthropogenic climate change impacts exacerbate summer forest fires in California, University of California, May 9, 2023; Union of Concerned Scientists, Causes and Consequences of Epic Western US Drought, March 17, 2022; NERC, 2023 State of Reliability Technical Assessment, June 2023, p. 8.

[273] SMA Solar Technology AG, Sunny Boy/Sunny Tripower Temperature Derating, Version 1.5 Technical Information, accessed December 12, 2023.

and increase the frequency and impact of wildfires, which in turn can reduce the transfer capabilities on the affected transmission infrastructure.[274]

Extreme cold weather events have had a sporadic but major impact on reliability over the last decade, including Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022. During winter storms with extreme cold air temperatures, demand for electricity and natural gas increase due to increased use of space and water heating as well as due to greater home occupancy. Such extreme weather conditions affect power plant generation capabilities due to freezing equipment, fuel unavailability for gas-fired units, stockpile freezes at coal-fired plants, ice blockages in river systems interfering with thermal plant cooling and hydropower intakes, turbine blade icing at wind plants, and snow cover at solar plants.[275]

With a greater proportion of gas generation (see Figure 16) in the current resource mix, weather-related outages of gas plants have become more impactful on the electricity system and highlight the need for better winterization of generation equipment and coordination between the gas and electricity sectors (see Section IV.D). For example, during the February 2021 Storm Uri event in the ERCOT region, demand for electricity increased drastically by about 9,000 MW (compared to the demand in the day before the storm), and 34,000 MW of supply was unavailable across a two-day period due to equipment or fuel-related outages. As a result, ERCOT initiated rotating outages to shed 20,000 MW of load, the most extensive rotating outages in U.S. history.[276] In contrast to most controlled outages, these blackouts had a major social impact, resulting in over 200 deaths and tens of billions in economic losses.[277]

Because winter events cause especially severe reliability impacts, they have been the special attention of FERC and NERC, who have developed new standards to address the concern.[278]

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[274] EPRI, Resource Adequacy Philosophy A Guide to Resource Adequacy Concepts and Approaches, December 2022, p. 20; NERC, 2023 State of Reliability Technical Assessment, June 2023, p. 30.

[275] EPRI, Resource Adequacy Philosophy A Guide to Resource Adequacy Concepts and Approaches, December 2022, p. 20

[276] ERCOT, "Hourly Load Data Archives: 2021," January 7, 2022, accessed December 4, 2023; FERC, NERC, Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, Nov ember 2021, p. 8.

[277] FERC, NERC, Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, November 2021, p. 234.

[278] FERC, FERC Approves Extreme Cold Weather Reliability Standards, Directs Improvements, February 16, 2023.

B. Future industry changes

The future electric power grid is expected to undergo a major transition in the next decades, continuing a shift from fossil fuel-based systems of energy production to renewable energy sources and energy storage resources. Wind and solar generation together are expected to become the largest sources of power in more regions; battery storage deployments will see major growth; electricity demand will accelerate; coal-fired generation will continue to retire; and there will be increasing grid regionalization and coupling.

On the supply side, these changes are expected to be driven largely by continued cost declines in renewable generation and battery storage, as well as policies and preferences to promote clean energy development.

On the demand side, electrification of heating in buildings, proliferation of electric vehicles, and the expansion of new sources of demand from data centers, greenhouses, and potentially hydrogen electrolyzers among others will offset much of the decline in demand from continued deployment of high-efficiency motor and lighting technologies. While demand nationally is expected to grow at a comparable pace to recent decades, some areas will experience significantly faster growth in demand. The commercialization of smart grid-connected technologies is expected to enable flexible demand or energy consumption that can be actively managed and controlled to complement variable renewable energy production and aid grid reliability.

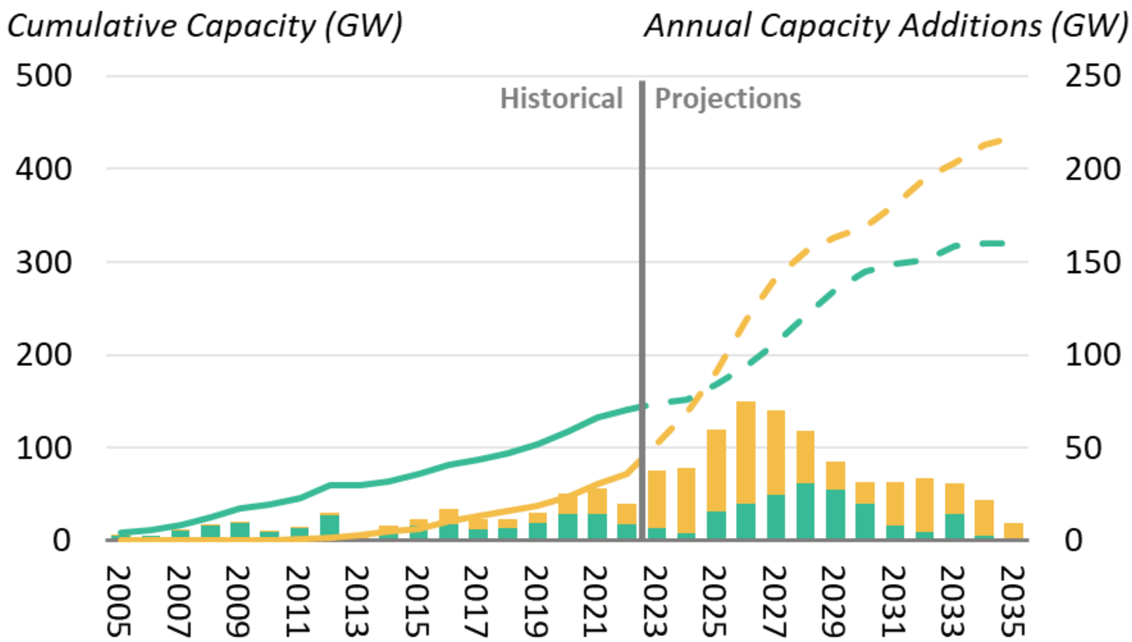
1. Accelerating wind and solar growth

Over the next decade, annual additions of wind and solar generation are expected to continue to increase at a faster rate than in the past. Annual installations of solar are expected to reach as high as 55 GW per year in 2026.[279] Based on this rapid growth, total installed capacity of solar is expected to overtake land-based wind in total installed capacity by the end of 2025.[280] The EIA projects that utility-scale solar capacity will more than triple in the next seven years, from approximately 100 GW in 2023 to nearly 340 GW in 2030, and continue growing at a rate of 18

[279] EIA, Annual Energy Outlook 2023, March 16, 2023, Table 16.
[280] *Ibid.*

GW annually from 2031 to 2035.[281] Total wind capacity is projected to reach 290 GW by 2030 and continue increasing at a rate of 6 GW annually from 2031 to 2035.[282] These are significant deployments compared to, for example, 1,176 GW of net U.S. installed capacity for all sources as of August 2023.[283]

FIGURE 24: HISTORICAL AND PROJECTED SOLAR AND WIND CAPACITY



Notes and Sources: Lines represent total installed capacity, bars represent annual capacity additions; EIA, Monthly Energy Review, 2023, Table 7.7b; EIA, Annual Energy Outlook 2023, March 16, 2023, Table 16.

The acceleration in wind and solar deployment will continue to increase the amount of variability and uncertainty of supply on the grid. In order to maintain reliability while taking advantage of this low-cost supply, grid operators will need to continue enhancing existing mechanisms designed to maintain reliability under variability and uncertainty.

Drivers of future accelerated wind and solar growth

Key drivers for the continued rapid deployment of wind and solar remain largely the same as past drivers: declining costs, increasing production efficiency, increasing customer preference for

[281] EIA, Annual Energy Outlook 2023, March 16, 2023, Table 16, 21, 22. Distributed solar is expected to grow at approximately 6 GW per year through 2035.

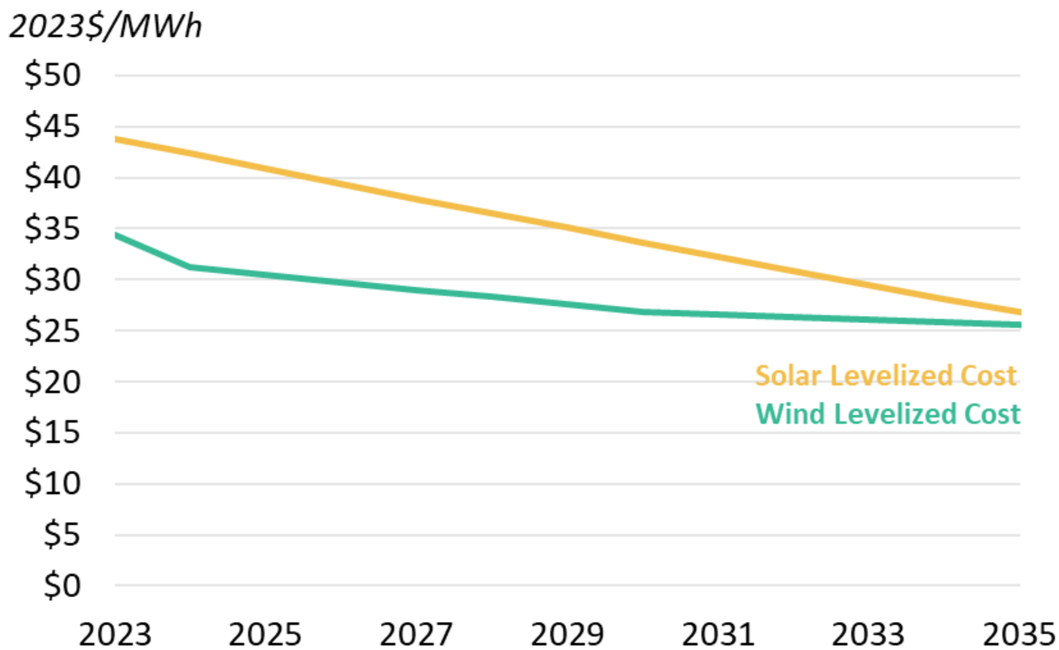
[282] EIA, Annual Energy Outlook 2023, March 16, 2023, Table 16.

[283] Represents net summer capacity, EIA, Monthly Energy Review, 2023, Table 7.7a.

cleaner generation as reflected by utility, state, and corporate decarbonization goals, and ongoing, expanded federal tax credits.

Wind and solar costs are projected to steadily decrease in long-term projections. NREL projects 26% and 39% decreases in real terms in contract prices for wind and solar respectively between 2023 and 2035, as shown in Figure 25.[284] These cost decreases are driven by technology improvements, efficiency gains in operations and maintenance, and innovations in controls technology.[285] These improvements are expected to drive down contract prices for new wind and solar power, which are already cost-competitive with existing combined-cycle natural gas generation (i.e., just fuel and maintenance costs).[286]

FIGURE 25: WIND AND SOLAR PROJECTED LEVELIZED COSTS



Notes and Sources: Class 5 averages shown for both wind and solar; NREL, 2023 ATB, 2023.

Wind and solar deployment will likely be further accelerated by the expansion in ambitious long-term clean energy targets of utilities, states, and cities, as well as corporations representing

[284] Cost projections based on NREL modeling of class 5 land-based wind and utility-scale solar resources; NREL, 2023 ATB, 2023.

[285] NREL, Annual Technology Baseline 2023: Land-Based Wind, 2023; NREL, Annual Technology Baseline 2023: Utility-Scale PV, 2023.

[286] This excludes the capital costs of building gas generators; LBNL, Utility-Scale Solar 2023 Edition, October 2023, p. 35; DOE, Land-Based Wind Market Report, 2023 Edition, August 24, 2023, p. 56, accessed November 28.

significant shares of the economy. Currently, 80% of U.S. customer accounts are served by an individual utility with a 100% carbon-reduction target by at least 2050 or whose parent company has a 100% carbon-reduction target by at least 2050.[287] In a similar vein, 23 states and Washington, D.C. are targeting 100% carbon-free electricity by at least 2050, and at least 35 of the 50 most populous cities in the U.S. have developed climate action plans to reduce emissions.[288] In the private sector, 109 large U.S. companies have enacted actionable emissions reduction plans evaluated by the Science Based Targets initiative.[289] These voluntary commitments, along with growing support for renewable energy from end customers, will contribute to the development of new renewable resources.[290] Finally, rooftop solar and other distributed energy resources will likely continue to grow as costs decline, technology to use on-site solar to provide backup power matures, building codes incorporate solar into new building design, community solar increases deployment and paired battery storage proliferates.

Wind and solar resources will also benefit from federal clean energy policies such as the 2022 Inflation Reduction Act, which extends tax credits to renewable resources based on project cost and energy production.[291] Renewable projects meeting wage, apprenticeship, siting, and domestic content requirements are now eligible to receive bonus tax credits at levels that exceed prior tax credits, which are expected to drive greater renewable capacity build-out.[292]

2. Ramping up deployment of storage resources

Energy storage technologies like batteries offer flexible and dispatchable capability that supports reliability without emissions. These technologies are well suited to complement wind and solar deployment, as they can charge during low-price hours when renewable output is high and provide rapid injections of energy as needed when renewable output is low, thereby supporting system reliability. These technologies, particularly battery storage, are poised to undergo a

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[287] Smart Electric Power Alliance, "Utility Carbon-Reduction Tracker," accessed December 17, 2023.

[288] Clean Energy States Alliance, "Table of 100% Clean Energy States," 2023, accessed December 13, 2023; Reuters, "Climate Change Mitigation in Local Government," August 2023, accessed December 17, 2023.

[289] Science Based Targets, STBi Monitoring Report 2022, August 2023, p. 12.

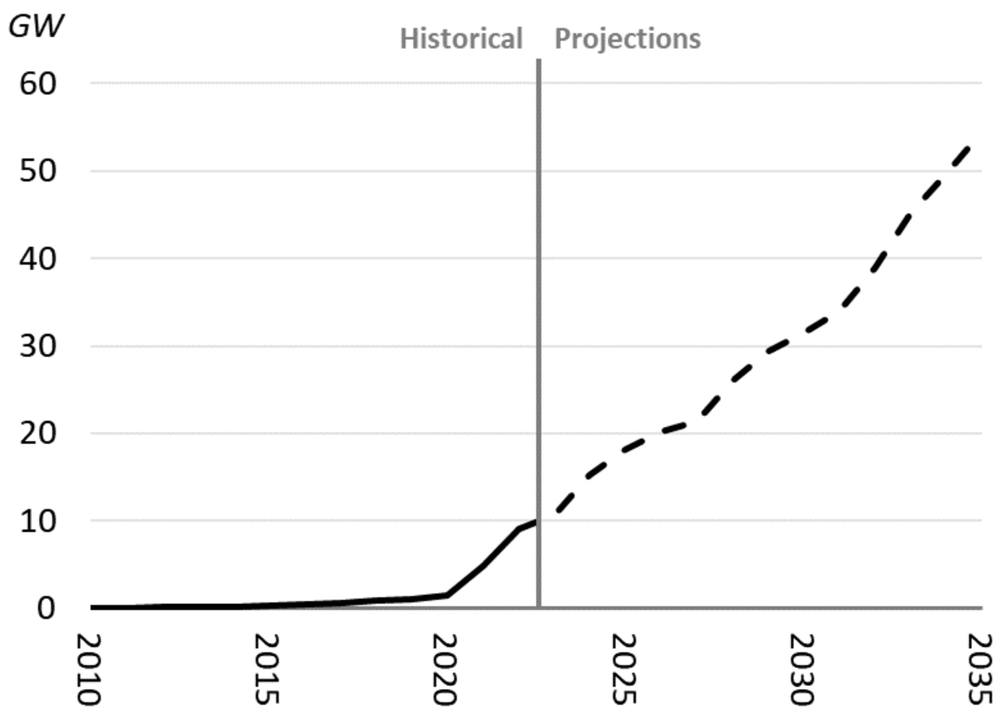
[290] Alec Tyson, et al., Americans Largely Favor U.S. Taking Steps to Become Carbon Neutral by 2050, Pew Research Center, March 1, 2022.

[291] LBNL, Utility-Scale Solar 2023 Edition, October 2023, p. 37; DOE, Land-Based Wind Report, 2023, p. xii; EPA, "Summary of Inflation Reduction Act provisions related to renewable energy," October 25, 2023, accessed November 21, 2023.

[292] Suyoung Moon, A Brief Overview of the Inflation Reduction Act's Clean Energy Tax Credit Provisions, American Bar Association, September 21, 2023.

period of rapid deployment in the future in both the near and long-term. Recently, built battery storage capacity has sharply increased, going from under 2 GW in 2020 to 14 GW (7 GW in CAISO, 3 GW in ERCOT, and the remainder elsewhere) in the span of three years (as of October 2023) with planned 2023 year-end installed capacity reaching 17 GW.[293] In the near term, 4-hour duration battery storage is projected to constitute the largest total capacity of all different battery storage durations.[294] As shown in Figure 26 below, total battery storage capacity is expected to reach 30 GW by 2030 and over 50 GW by as early as 2035, more than three times the current built and planned battery storage capacity.[295]

FIGURE 26: PROJECTED FUTURE U.S. STORAGE DEPLOYMENT



Notes and Sources: Excludes pumped storage. 2023 data shown in figure is projection from EIA Annual Energy Outlook 2023, but updated projections from EIA 860M reflect 17 GW of planned battery capacity by the end of 2023. Historical data from EIA, Monthly Energy Review, 2023, Table 7.7b; Future data from EIA, Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 9. For updated data on planned battery capacity, see EIA, "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA 860)," November 22, 2023, October 2023 data, accessed November 28, 2023.

293 2023 battery storage capacity as of October 2023, see EIA, "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA 860)," November 22, 2023, October 2023 data, accessed November 28, 2023; EIA, Monthly Energy Review, 2023, Table 7.7b.

294 Nate Blair, et al., Storage Futures Study: Key Learnings for the Coming Decades, NREL, 2022, p. 3.

295 EIA, Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 9.

Drivers of future deployment of storage resources

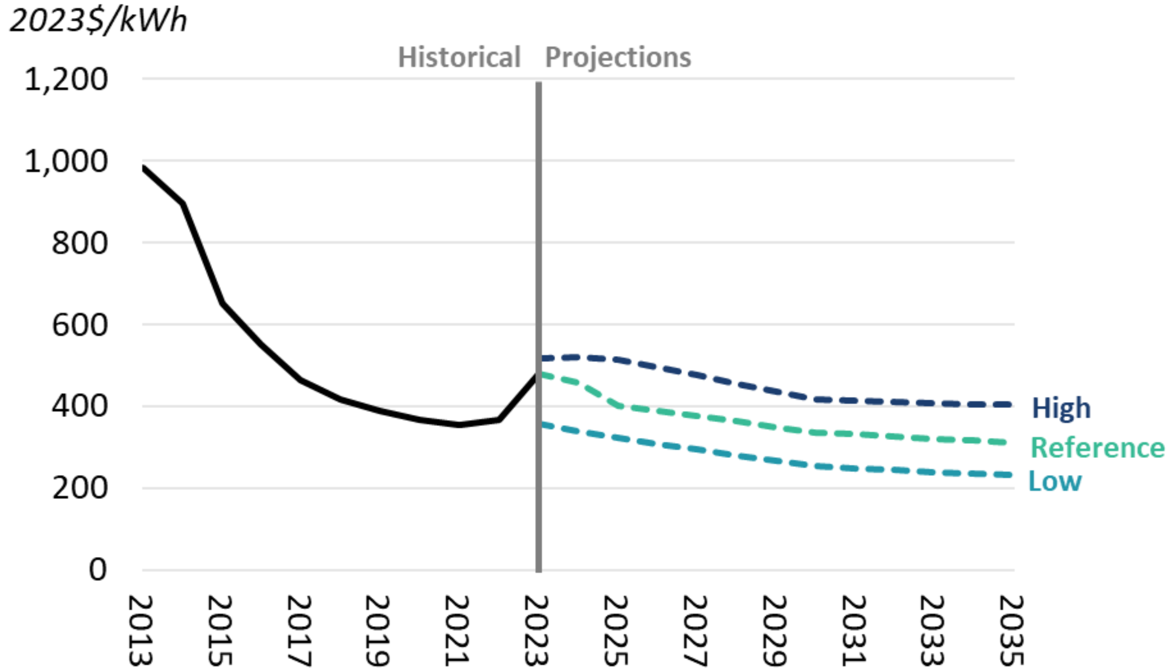
Key drivers of future battery storage deployment include continued cost declines of lithium ion battery packs, the increasing value of flexibility and dispatchable capacity (particularly driven by solar PV penetration), and beneficial state and federal clean energy policies. Environmental regulations have an indirect impact on this trend since batteries are a faster-acting and cost-competitive replacement for flexibility that traditional thermal resources have provided previously; that is, to the extent that environmental regulations increase costs of operating the existing emission-intensive resources relative to the cost of installing and operating battery storage resources, they could contribute to increasing the rate of storage deployment as a replacement resource.

Lithium-ion battery pack costs have dropped by more than 63% in real terms between 2013 and 2022 and are expected to continue to fall, as shown in Figure 27.[296] The initial sharp decrease in costs have been predominately due to improvements on the technology learning curve and the build-out of manufacturing capabilities, with future cost declines enabled by continued scale of production driven by electric vehicle adoption. While battery storage costs experienced an increase in 2022/2023 due to supply chain constraints and high inflation in the wake of the COVID-19 pandemic among other factors, those are expected to be short-term trends, and NREL projects steady declines in the long term from approximately $479/kWh in 2023 to approximately $310/kWh by 2035 in the reference scenario.[297]

[296] Historical data for battery facilities are based on Bloomberg battery pack cost estimates plus a cost-adder of $206/kWh in 2023$ which accounts for additional component (battery management systems, balance of system, inverters, etc.) and soft costs (taxes, overhead, developer costs, etc.) for the remainder of facility costs. See BNEF, Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh, November 27, 2023.

[297] Battery storage costs increased slightly in 2022/2023 predominately due to supply chain constraints which increased costs for raw materials and critical components. Additionally, the costs of energy, freight and labor all increased due to the high inflationary environment in the wake of the COVID-19 pandemic and the Russian invasion of Ukraine. See Mark Nicholls, Inflation bites at the battery storage bonanza, Energy Monitor, June 10, 2022; Robin Whitlock, Lithium-ion battery pack prices increase due to rising costs of materials and components, Renewable Energy Magazine, December 6, 2022. The three NREL cost scenarios represent varying levels of technology innovation. See NREL, "Technical Limitations," ATB 2023, 2023, accessed November 28, 2023.

FIGURE 27: HISTORICAL AND PROJECTED COST DECLINES OF UTILITY-SCALE BATTERY STORAGE FACILITIES



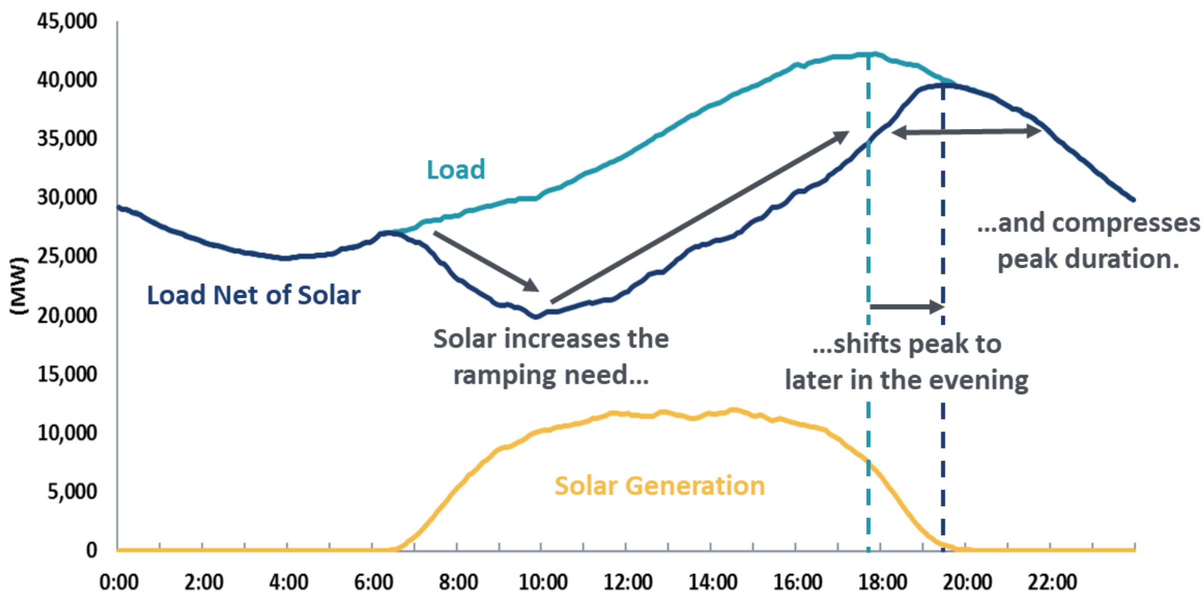
Notes and Sources: Historical data for battery facilities are based on Bloomberg battery pack cost estimates plus a cost-adder of $206/kWh in 2023$ which accounts for additional component (battery management systems, balance of system, inverters, etc.) and soft costs (taxes, overhead, developer costs, etc.) for the remainder of facility costs; projections of battery facility costs are NREL 2023 Annual Technology Baseline estimates for 4-hour, utility-scale lithium ion battery storage. See BNEF, Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh, November 27, 2023; NREL, 2023 ATB, 2023.

Flexibility, the ability to quickly increase/decrease generation or increase/decrease load, is increasingly valuable to handle the variability and uncertainty in output of growing amounts of solar and wind generation. Similarly, capacity for resource adequacy, or the ability to generate or reduce demand at specific tight supply hours year-round, remains valuable as well, with a growing focus on non-polluting resources. Battery storage is well suited to providing both capabilities since it has a near instantaneous response time and can be a source of clean dispatchable power, whether or not it is paired with solar or wind.

The flexibility and capacity value of battery storage is particularly correlated to solar PV penetration. Since PV increases the ramping need and sharpens the net peak load profile (see Figure 28), battery storage can lower more of the net peak as well as provide flexibility for the new ramping requirements, thereby becoming more valuable in power systems with substantial solar.

Due to these synergies between solar and batteries, policies that incentivize solar deployment indirectly increase the value of storage, while federal tax incentives such as the ITC were recently updated to include standalone storage as an eligible technology to receive tax credits.[298] State mandates specifically for storage capacity will also drive deployment. Furthermore, in regions where renewable energy credit prices are high, the value of installing storage that can reduce renewable energy curtailment is also high.[299]

FIGURE 28: EXAMPLE OF SOLAR NET LOAD IMPACTS (CALIFORNIA AUGUST 12, 2021)



Notes and Sources: Adapted from Sam Newell, et al., Capacity Resource Accreditation for New England's Clean Energy Transition, Report 1: Foundations of Resource Accreditation, The Brattle Group, June 2, 2022, p. 10.

3. Increased electricity demand growth

Electricity demand growth is expected to increase in the near and long-term future after a period of flat national demand from 2007 to 2020. This load growth will require a corresponding increase in installed capacity and an augmentation of resource flexibility to maintain system reliability, especially given high renewable penetration. However, there is uncertainty regarding how much future demand growth will materialize depending on decarbonization efforts and development of new sources of demand.

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[298] EPA, "Summary of Inflation Reduction Act provisions related to renewable energy," October 25, 2023, accessed November 21, 2023.

[299] A. Will Frazier, et al., Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector, NREL, 2021, p. 11.

Projections of peak demand growth are not uniform with pockets of higher than average growth expected across the country. NERC projects moderate national peak demand growth of 0.98% in the summer and 1.23% in the winter through 2033 (both up from prior forecasts), and other studies point to higher forecasts; this variation may in part be due to inconsistent modeling of emerging load growth drivers.[300]

Meanwhile utilities in some areas undergoing greater economic development are expecting substantially higher peak demand growth. Arizona Public Service Company expects 2.4% average annual growth in summer peak demand between 2023 and 2038 driven by new demand from large industrial customers, data centers, and electric transportation.[301] Similarly, Georgia Power predicts an 2.7% average annual growth in winter peak load between 2024 and 2043 due to expansion of manufacturing, electric transportation, data centers, and other businesses.[302] At the extreme of high utility demand growth forecasts, Dominion Energy expects a 4.4% annual peak demand growth driven by new data center demand in Virginia (2023 to 2038).[303]

Drivers of accelerating growth in demands

Baseline demand growth is expected due to population and economic growth as well boosted economic activity as the U.S. economy continues to normalize after the COVID-19 pandemic. Higher demand growth beyond baseline expectations is possible (and in many places likely) due to the anticipated growth in electric vehicles and electrified heating. Additionally development of new sources of demand could greatly increase demand growth. In the short term, this includes sources such as data centers, greenhouses, and reshoring of manufacturing, while in the long term, this could include sources such as hydrogen electrolyzers and carbon dioxide removal like direct air capture.[304]

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300 NERC, 2023 Long-Term Reliability Assessment, December 13, 2023, Supplemental Charts and Graphs, Table H; John Wilson and Zach Zimmerman, The Era of Flat Power Demand is Over, Grid Strategies, December 2023.

301 Arizona Public Service Company, 2023 Integrated Resource Plan, November 2023, pp. 18-19.

302 Georgia Power, 2023 Integrated Resource Plan Update, October 2023, p. 10.

303 PJM, Load Forecast Report, January 2023, pp. 35-36.

304 EPRI, Reindustrialization, Decarbonization, and the Prospects for Demand Growth, 2023; McKinsey & Company, Investing in the rising data center economy, January 17, 2023; Jared Anderson, et al., Power of AI: Wild predictions of power demand from AI put industry on edge, S&P Global, October 16, 2023; The White House: Office of Science and Technology Policy, "FACT SHEET: Climate and Energy Implications of Crypto-Assets in the United States," September 8, 2022, accessed December 4, 2023; DOE, "Regional Clean Hydrogen Hubs," accessed December 4, 2023; Robert Walton, Pot, EVs, data to lead electricity demand growth: Morningstar, Utility Dive, December 5, 2018; Jeremy David and Howard Herzog, The Cost of Carbon Capture, Massachusetts Institute of Technology, October 2011.

Electrification of the transportation sector through adoption of electric vehicles is expected to be a significant driver of future electricity demand.[305] Adoption rates of electric vehicles will be primarily driven by cost and capability comparisons to conventional combustion engine vehicles. Currently total cost of ownership of passenger electric vehicles is either comparable to or substantially cheaper than equivalent combustion vehicles (depending on the vehicle class), and costs are expected to decrease further in line with battery cost reductions (see Figure 27).[306] According to the conservative estimates from the EIA, the electric vehicle stock in the U.S. is projected to increase from around 3 million in 2022 to between 12 and 24 million vehicles by 2030, representing 11% to 26% of total light-duty sales in 2030.[307] Other estimates predict future sales shares more in line with the national goal of 50% by 2030, as set by the Biden Administration in 2021, as shown in Figure 29.[308] Additionally, several U.S. states have set 100% sales share targets for zero emissions vehicles by 2035. For context, if adoption rates achieve stated goals, electric vehicle electricity demand could rise from 100 TWh/year in 2030 (representing around 2% of total annual energy demand) to 930 TWh/year in 2050, or approximately 20% of total annual energy demand.[309]

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[305] Trieu Mai, et al., Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States, NREL, 2018.

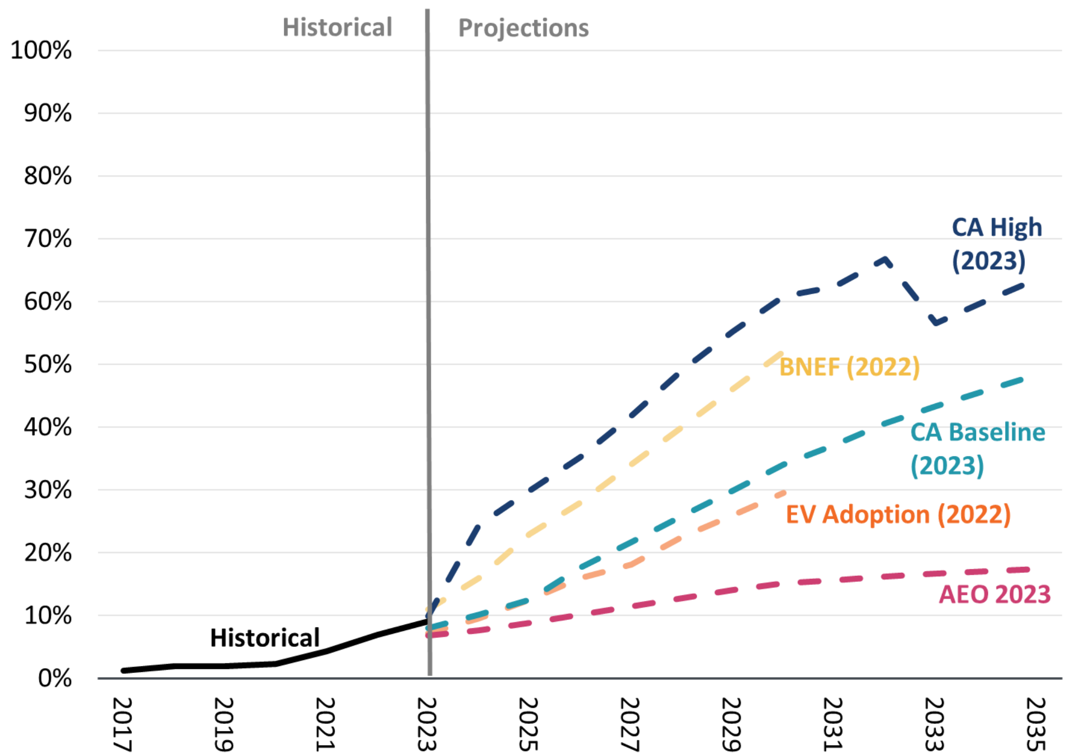
[306] Environmental Defense Fund, Electric Vehicle Total Cost of Ownership Analysis: Summary Report, July 2023.

[307] Includes electric vehicles and plug-in hybrid electric vehicles; EIA, Annual Energy Outlook 2023, March 16, 2023, Table 38; EIA, Annual Energy Outlook 2023, March 16, 2023, Table 39.

[308] Section 177 of the Clean Air Act allows other states to adopt California's vehicle emissions standards. As of 2023, five states (Washington, Massachusetts, New York, Oregon, and Vermont) have adopted standards equivalent to the most recent (finalized in 2022) California Air Resources Board Advanced Clean Cars II (ACC II) program, which will require manufacturers to sell 100% zero emissions vehicles by 2035. See Arthur Yip, et al., Highly Resolved Projections of Passenger Electric Vehicle Charging Loads for the Contiguous United States, NREL, June 2023, p. 23; The White House, Executive Order on Strengthening American Leadership in Clean Cars and Trucks, August 5, 2021.

[309] NREL scenario whereby EV demand reaches 930 TWh/year in 2050 reflects EV sales reaching 50% in 2030 and 100% in 2035. The former target is consistent with the national goal as set in the Biden Administration Executive Order, and the former target is aligned with several other state and non-federal targets; calculation of EV sales as percent of future load based on NREL projections of electric vehicle electric load compared to EIA electricity demand (Reference Case). See Arthur Yip, et al., Highly Resolved Projections of Passenger Electric Vehicle Charging Loads for the Contiguous United States, NREL, June 2023, pp. 22-23,29-30; EIA, Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 54.

FIGURE 29. MARKET SHARE OF ELECTRIC LIGHT-DUTY VEHICLE SALES, UNITED STATES (2017-2035)



Notes and Sources: For historical data through October 2023, see Argonne National Laboratory, "Light Duty Electric Drive Vehicles Monthly Sales Update," 2023, accessed November 29, 2023. For projections, see Sara Baldwin, California's Electrification Technology Market Outlook Panel, Energy Innovation: Policy and Technology LLC, January 31, 2023, p. 8; Ira Boudway, More Than Half of US Car Sales Will Be Electric by 2030, BNEF, September 20, 2022; EV Adoption, "EV Sales Forecasts," 2023, accessed December 5, 2023; EIA, Annual Energy Outlook 2023, March 16, 2023, Table 38.

Residential and commercial buildings are electrified to a high degree, with electricity already accounting for between 60%-75% of all energy use. Further electrification potential for buildings therefore rests primarily in water and space heating.[310] Heat pumps are an attractive technology for electrifying this end-use due to their high energy efficiency and multi-use potential to provide heating and cooling and, in the case of integrated systems, water heating as well. Electrification of heating is not expected to have as much of an impact on increasing overall annual electric demand for energy since cars are driven year-round but heating is focused primarily in the winter. However, electric heating is expected to have to have an outstated impact on annual peak demand, especially in many cold regions, which will cause these regional systems to switch from summer to winter peaking (particularly in the Northeast U.S.). This seasonal peaking switch has

[310] Trieu Mai, et al., Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States, NREL, 2018.

substantial implications for reliability planning since many traditional approaches were summer focused (see Section III and Appendix B for full discussion).

New sources of demand are also expected to develop in the future. Electricity demand by data centers in the US was estimated to be roughly 96-136 TWh in 2022.[311] McKinsey & Company estimates that data center energy usage will more than double by 2030, which could leave to an excess of 200 TWh of energy consumption by data centers in that year.[312] Similarly, electricity demand from greenhouses could grow from 15 TWh in 2018 to 65 TWh and become as much as 1.5% of total U.S. electricity energy consumption by 2030.[313]

While electrification and new sources of load will increase electricity demand, continued replacement of lighting with more efficient LED lighting and industrial electric motors with Variable Frequency Drives (VFD) and other improvements will continue to temper demand growth. LED lighting accounted for only around 30% of indoor lighting and little over half (51.4%) of outdoor lighting nationwide for all sectors as of 2018.[314] By 2020, nearly half of all residential homes used LEDs for all or most of their indoor lighting.[315] As of 2021, industrial facilities have only 16% of motor capacity using VFDs on average and commercial facilities are even lower with only 4% using VFDs.[316] These reports show that substantial energy efficiency potential still remains in these sectors.

Finally, recent developments of integrating smart, grid-connected technology into appliances, buildings, and electric vehicles (known as Vehicle-to-Grid, V2G) will enable flexible load that can be actively managed to minimize grid impacts. Comprehensive studies of future demand have

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311 The U.S. accounts for roughly 40% of the global data center market in terms of energy demand, according to McKinsey & Company. The International Energy Agency estimates that data centers consumed 240-340 TWh globally in 2022. United States data center energy consumption can therefore be estimated around 96 -136 TWh in 2022. See Srini Bangalore, et al., Investing in the rising data center economy, McKinsey & Company, January 17, 2023; International Energy Agency, "Data Centers and Data Transmission Networks," 2023, accessed December 15, 2023.

312 U.S. data center capacity is forecasted to grow by approximately 106% from 2022 - 2035, according to McKinsey & Company. Applying this same growth rate to estimated U.S. data center energy consumption yields estimates of 198 – 280 TWh of data center consumption in the U.S. in 2030. See Srini Bangalore, et al., Investing in the rising data center economy, McKinsey & Company, January 17, 2023; International Energy Agency, "Data Centers and Data Transmission Networks," 2023, accessed December 15, 2023.

313 Robert Walton, Pot, EVs, data to lead electricity demand growth: Morningstar, Utility Dive, December 5, 2018.

314 DOE, Adoption of Light-Emitting Diodes in Common Lighting Applications, August 2020, pp. 2-3.

315 EIA, Nearly half of U.S. households use LED bulbs for all or most of their indoor lighting," March 31, 2022.

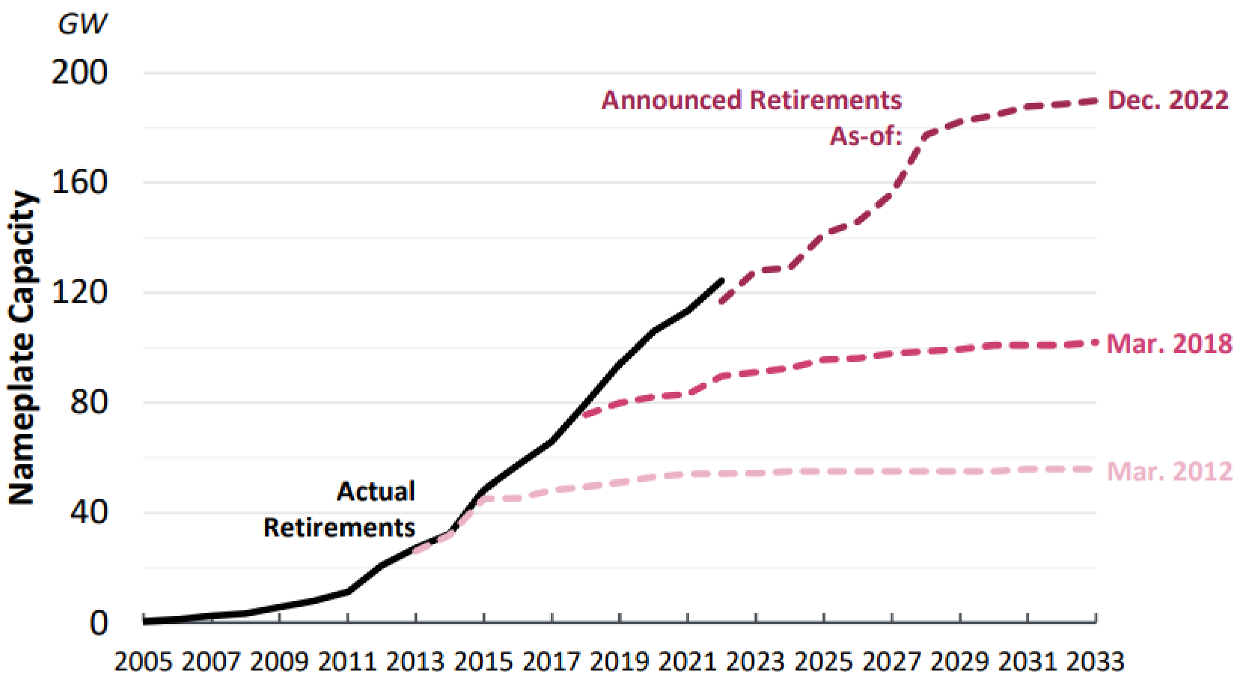
316 Prakash Rao, et .al., U.S. Industrial and Commercial Motor System Market Assessment Report: Volume 1 Characteristics of the Installed Base, LBNL, January 2021, p. 117.

found that even under high electrification and renewable energy scenarios the grid can be successfully operated and flexible demand can actually enhance operational efficiency by reducing renewable energy curtailment and increasing utilization of generators that have lower operating costs.[317]

4. Continued coal plant retirements

Coal plants will continue to retire in the future, with approximately 68 GW already announced for retirement by the end of 2030.[318] If historical trends offer an indication, the total capacity of announced coal plant retirements is likely an underestimate of future actual retirements as shown in Figure 30 below.

FIGURE 30: ANNOUNCED AND ACTUAL CUMULATIVE COAL PLANT RETIREMENTS



Notes and Sources: Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023, p. 7.

[317] NREL, Electrification Futures Study: Operation Analysis of U.S. Power Systems with Increased Electrification and Demand-Side Flexibility, May 2021, p. 55.

[318] Data as of December 2022; Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

Drivers of future coal plant retirements

Future coal plant retirements will likely be subjected to continuations of past drivers, namely competition from cheaper renewables, increasing operating costs of an aging coal fleet, and state-level decarbonization goals. Future coal retirements will likely also be driven by new developments such as battery storage emerging as another cost-effective replacement resource, provisions in the recently passed Inflation Reduction Act that further increase the economic attractiveness of clean energy resources (wind, solar, and battery storage) relative to coal, and more ambitious state-level decarbonization goals. As has been the case with past retirements of coal plants, additional compliance costs associated with new environmental regulations will continue to be one of many factors reducing the economic viability of coal plants in the future.

Recently, batteries and other storage technologies have begun to emerge as part of an economically attractive portfolio of resources to replace coal plants. In some cases, storage has been built on or near retiring coal plant sites to take advantage of further cost savings from the ability to reuse existing infrastructure and grid interconnection rights.[319] This trend is expected to accelerate as battery storage costs continue to decline and other longer duration storage technologies become commercialized.

The Inflation Reduction Act (IRA) is expected to greatly increase wind, solar, and battery storage capacity and decrease coal capacity as its incentives amplify trends already underway. A recent meta-study combining results from eleven independent models to examine potential implications of key provisions in the IRA concluded that IRA incentives will lead to 10-99 GW/yr of additional solar and wind (56 GW/yr average) and 1-18 GW/yr of additional battery storage (7 GW/yr average) through 2035.[320] This same study concluded that the IRA will lead to 4-17 GW/yr of coal plant retirements (11 GW/yr average) compared to 1-8 GW/yr of retirements (6 GW/yr average) in control scenarios without the IRA.[321] Results also indicated that the IRA incentives will result in reducing the output of coal plants by 44-100% from 2021 levels by 2035 compared to 12-63% in control scenarios without the IRA, highlighting the substantial impact of the IRA on future generation from coal plants.[322]

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319 Paul Ciampoli, Former Coal Plant Sites Get Second Life With Energy Storage Systems, American Public Power Association, September 11, 2023.

320 John E T Bistline, et al., Power sector impacts of the Inflation Reduction Act of 2022, November 30, 2023, p. 2-5.

321 John E T Bistline, et al., Data for Bistline, et al. (2023) "Power Sector Impacts of the Inflation Reduction Act of 2022", October 31, 2023, IRA Power Comparison – Historical Additions Data.

322 *Ibid*, p. 6.

Of the 29 states with renewable portfolio standards, 12 states have recently added additional clean energy or net-zero goals which envision a very limited or non-existent role for coal in their carbon-free future.[323] Minnesota and Illinois both have goals to reach a 100% clean electric grid by 2040 and 2050 respectively.[324] Most recently, Michigan introduced a 100% clean electricity standard by 2040.[325]

5. Increasing grid regionalization and coupling

In future years, many utilities across the Western U.S. are expected to join energy and capacity-pooling programs designed to standardize resource adequacy requirements as well as coordinate real-time and day-ahead procurement and dispatch of energy. Within the next few years, new day-ahead markets will complement the already-existing WEIS and WEIM and feature a joint optimization to minimize production costs in both day-ahead and real-time markets.[326] Similarly, many utilities have already joined the nascent Western Resource Adequacy Program, which features central resource adequacy planning, compliance, and capacity sharing.[327] Regarding existing ISOs/RTOs, SPP plans to expand its footprint westward, while states including Nevada and Colorado have mandated their utilities join a wholesale market by 2030 and others are considering joining an ISO/RTO.[328]

Figure 23 illustrates the rapidly accelerating pace of grid regionalization. In 2014, the WEIM only covered two control areas (CAISO and PacifiCorp). Since 2014, WEIM has expanded to 22 control areas, while SPP has created the WEIS and Markets+ markets while and EDAM and WRAP have also come into existence. As shown in Figure 23 the geographic extent of regionalized wholesale

[323] Data as of November 2022; Metin Celebi, et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

[324] Clean Energy States Alliance, "Table of 100% Clean Energy States," 2023, accessed December 13, 2023.

[325] Michigan State Department of Environment, Great Lakes, and Energy, Michigan becomes a national leader in climate action with new legislation, making progress on the goals of the MI Healthy Climate Plan, November 28, 2023.

[326] The day-ahead market that will build on WEIM is the Extended Day Ahead Market (EDAM), while the day-ahead market that will build on WEIS is Markets+; CAISO, EDAM: Extended Day-Ahead Market, 2023; SPP, Markets+: A Proposal for Southwest Power Pool's Western Day-Ahead Market and Related Services, November 30, 2022.

[327] WRAP is slated to begin binding operations in 2025; It is composed of 22 utilities in the non-ISO/RTO Western US. See WRAP, Western Resource Adequacy Program Detailed Design, March 2023, p. 20; WRAP, "WRAP Area Map," April 5, 2023, accessed December 4, 2023.

[328] John Tsoukalis, et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, The Brattle Group, April 27, 2023, p. 46; SPP, "RTO West," 2023, accessed December 15, 2023; David Hurlbut, et al., Impacts of Expanded Regional Cooperation on California and the Western Grid, January 13, 2023, pp. 22-26.

markets has expanded dramatically to increase reliability throughout the West. Currently, the expansion of markets has spread to more than 100 unique utilities across more than 30 control areas in the West.[329]

Drivers of future increased grid regionalization and coupling

Future drivers of grid regionalization are similar to drivers in the recent past, namely reduced total costs and greater options to maintain reliability (see Section A). In a future characterized by increased wind and solar penetration and decreased reliance on thermal generation, resource pools will be especially important to facilitate the transfer of electricity and capacity across broad geographical areas with different peak and net peak hours. Extended real-time, day-ahead, and capacity-sharing markets will prevent the erosion of reliability outcomes under the changing resource mix of the future. Accessing diverse forms of generating capacity will support emerging needs for flexibility and quick-start resources, as discussed in more detail in Section IV.B.

[329] EIA, "Electric Retail Service Territories," December 9, 2022, accessed November 30, 2023; WEIM, "About: Active Participants," 2023, accessed November 30, 2023; CAISO, "EDAM: Extended Day Ahead Market," accessed November 29, 2023; SPP, "Western Energy Imbalance Service Market," 2023, accessed November 30, 2023; SPP, "Markets +," accessed November 30, 2023; Western Power Pool, "WRAP Area Map," November 21, 2022, accessed November 30, 2023.

Appendix B: Defining Reliability

A. The value and challenge of electric grid reliability

Electricity has long been essential for modern life: powering factories, heating and cooling buildings and food, and providing lighting, communication, and various forms of transportation (e.g., subways and some commuter trains). The power sector has therefore invested in reliability to ensure that, even during the most challenging circumstances, customers can access the value of electricity. The value of electricity constitutes the foundation for reliability.

How valuable is electricity? We can observe that regional blackouts cause lost productivity and in some cases harm or death.[330] Moreover, surveys of end-use customers reveal a high willingness to pay to continue operating high-value factories (not just to maintain operating profits, but in some cases to avoid damaging costly plant equipment) or to keep a building warm on an extremely cold day (or cool on a hot day).[331] While the cost to produce electricity is generally less than $0.10/kWh, the value of electricity to customers is often more than 100 times higher.[332] Surveys show that the value varies based on the specific customer, duration of interruption, season, weekday versus weekend, and many other factors. The value can range

[330] For example, the 2003 Northeast Blackout was estimated to have reduced U.S. earnings by approximately $6.4 billion, see Patrick Anderson and Ilhan Geckil, Northeast Blackout Likely to Reduce US Earnings by $6.4 billion, Anderson Economic Group, August 19, 2003, p. 2. The Texas Department of State Health Services confirmed 246 deaths related to winter storm Uri and subsequent widespread blackouts in February 2021. Of these 246 deaths, an estimated 205 deaths were related to extreme cold exposure, exacerbation of pre-existing illnesses (respiratory, cardiovascular, renal, or other), and carbon monoxide poisoning due to incorrect usage of generators, all of which can be directly tied to the blackouts during storm Uri, see Texas Department of State Health Services, February 2021 Winter Storm-Related Deaths – Texas, December 31, 2021, p. 7.

[331] For example, outages are extremely damaging for aluminum smelters, as severe power outages can lead to loss of production and the shutdown of potlines, which damages pots and shortens their lifetime, see Harald Øye, and Morten Sørlie, Power failure, restart and repair, Aluminum International Today, 2011, p. 1-4.

[332] Nonetheless, in some circumstances the value of electricity can be low, for example residential customers at night, during which interruptions exhibit a much lower value of lost load than during the day. Eimear Leahy and Richard Tol, An Estimate of the Value of Load for Ireland, Economic and Social Research Institute, Dublin, October 2010, p. 7.

from \$0.90/kWh to over \$2,000/kWh (compared with a typical retail rate of around \$0.10-\$0.15/kWh).[333]

It has not historically been practical to store electricity in large quantities, unlike other essential commodities like food, water, or fuels.[334] Therefore, the precise level of total demand for electricity must effectively be produced and delivered continuously at the moment the customers demand it. This is the fundamental technical challenge of making electricity available to customers at all times.

The core of decades of electric reliability management practice is defined by the combination of (1) the exceptionally high value of electricity for the majority of customers; and (2) the challenge of matching power production continuously to demand despite highly variable and uncertain demand. **Indeed, electric grid reliability can be defined as the ability to ensure electricity is continuously available.**[335]

These twin drivers explain large investments in resources and facilities, some of which are seldom fully used except during the hours with the highest demand conditions. They also explain why owners of many homes as well as most large commercial buildings, factories, and communication facilities invest in on-site backup generation facilities to ensure consistent access to electricity in case of loss of utility power, even when those backup facilities are almost never used.[336] The value of avoiding lost power for even a handful of hours per year justifies such investments for many types of customers.

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[333] MJ Sullivan, et al., Estimated Value of Service Reliability for Electric Utility Customers in the United States, Ernest Orlando Lawrence Berkeley National Laboratory, June 2009, pp. xxi; EIA, "US Electricity Profile 2022," November 2, 2023, accessed December 15, 2023.

[334] There is in fact some limited amount of storage in the electric power system, including (in large grids) a few seconds of energy stored in the mechanical inertia of rotating machines like motors and spinning generators. Outside of this limited storage, all other storage technologies either store fuel for future use (such as gas storage, coal, etc.) or convert electrical energy to another form of energy (mechanical energy, chemical energy, thermal energy, etc.) for conversion back to electricity in the future. This latter category includes a range of common storage technologies such as lithium-ion batteries, pumped storage hydropower, thermal storage, compressed air energy storage, etc. See MIT Energy Initiative, The Future of Energy Storage, June 3, 2022.

[335] For example, FERC provides this simple definition of reliability: "*Grid reliability is the provision of an adequate, secure, and stable flow of electricity as consumers may need it. In other words, when you flip the light switch, the lights turn on.*" See FERC, "Reliability Explainer," August 16, 2023, accessed November 10, 2023.

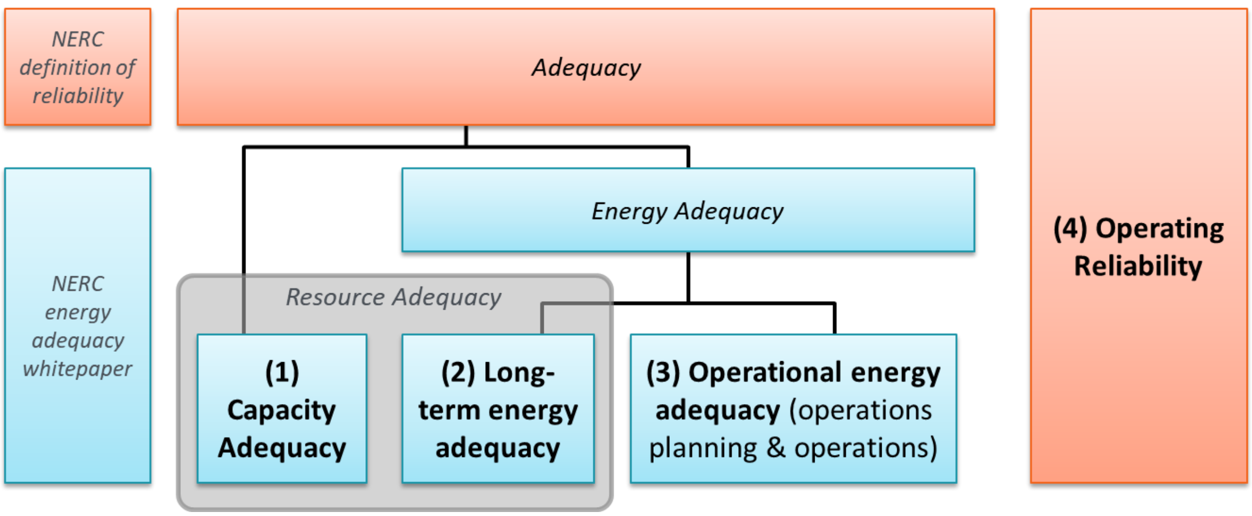
[336] Julia A. Phillips, et al., Onsite and Electric Power Backup Capabilities at Critical Infrastructure Facilities in the United States, Argonne National Laboratory, April 2016, p. 7-8.

As society relies on computing and communication in new ways, as non-electric substitute sources of energy for buildings (such as gas and other fuel-based heating) slowly decline, and as customers choose to rely more on electric vehicles, the demand for and critical value of electricity grows still higher.[337]

B. The four aspects of reliability

Between NERC's longstanding definition of reliability, and its emerging work on energy adequacy, one can define four aspects of reliability that are central to the evolutions in the grid today, as shown in Figure 31.

FIGURE 31: THE FOUR ASPECTS OF RELIABILITY AND THEIR RELATIONSHIP TO NERC DEFINITIONS



Notes and Sources: the terms "adequacy" and "operating reliability" are from NERC, Reliability Terminology, 2013; the term "energy adequacy" and its two subtypes are from NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December 2020.

CAPACITY ADEQUACY AND LONG-TERM ENERGY ADEQUACY

We use the term "resource adequacy" here to refer to the property of a system that it has sufficient resources with the right characteristics to meet demand all the time. The NERC regional entity for the Mid-Atlantic and Great Lakes regions defines resource adequacy as "*the ability of*

[337] Indeed, as direct use of fossil fuels overall continues to slowly decline in share (in all sectors) relative to electricity consumption (which has increased in all sectors) since the 1970s, see EIA, Monthly Energy Review, July 2023, Tables 2.1a-2.5. Per the American Institute of Architects (AIA), the number of all-electric building projects reported by firms in their sample increased by 134% relative to the number reported in 2020, see AIA, 2030 By the Numbers: the 2022 Summary of the AIA 2030 Commitment, September 2023, p. 24.

supply-side and demand-side resources to meet the aggregate electrical demand (including losses)."[338] Within resource adequacy, "capacity adequacy" holds when sufficient resources are installed such that supply can meet peak demand to within a specified threshold (i.e., under all but the most extreme expected peak demand). NERC emphasizes that "*historically, analysis of the resource adequacy of the BPS [Bulk Power System, the NERC-jurisdictional transmission system] focused on capacity over peak time periods. Assessment of resource adequacy focused on capacity reserve levels compared to peak demand because resources were generally dispatchable and, except for unit outages and de-rates, were available when needed*."[339] For that reason, resource adequacy has historically focused on capacity adequacy in the U.S., with other types of adequacy planning managed on the periphery.

Coal generation, natural gas generation, wind and solar generation, and energy storage all feature meaningful albeit quite distinctive limitations on their ability to produce power on demand. During the most extreme winter weather, when winter demand for electricity is the highest, natural gas generators have higher rates of equipment failure and are sometimes unable to obtain sufficient deliveries of natural gas (which is in high demand for heating), while coal generators also can suffer from higher rates of failure due to a variety of causes, including frozen coal piles, frozen cooling water, and equipment failures.[340] Wind and solar availability varies widely depending on the weather. Energy storage has high technical availability but limited energy storage capability. Because deployment of new resources types have been growing quickly and will continue to grow, the study of the interaction of emerging limitations on the ability to meet demand for power has been rising in prominence. Such studies fall under the umbrella of "energy adequacy", the subject of the NERC Energy Reliability Assessment Task Force, launched in 2021.[341] NERC equates energy adequacy with "*more advanced probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy*" and "*assessment of resource adequacy across all hours*."[342] The authors of MISO's RIIA report define energy adequacy as "*the electric system's ability to operate continuously to*

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338 NERC, Planning Resource Adequacy Analysis, Assessment and Documentation, Standard BAL-502-RFC-02, p. 7.

339 NERC, Ensuring Energy Adequacy with Energy-Constrained Resources, December 2022.

340 For example, compare outage rates for coal and gas shown for two cold weather events in Table 2 and Table 3 of NERC's 2021-2022 Winter Reliability Assessment (for affected ISOs/RTOs, ranging as high as 27% for coal and 42% for gas) to the national average generator outage rate for coal (around 10% - 14%) and gas (7% - 9%) between 2018-2022 from NERC's State of Reliability report. NERC, 2021-2022 Winter Reliability Assessment, November, 2021. NERC, 2023 State of Reliability Overview, June 2023, Figure 3: Monthly Weighted Equivalent Forced Outage Rate by Fuel Type.

341 NERC, Energy Reliability Assessment Task Force, accessed December 17, 2023.

342 NERC, 2020 Long-Term Reliability Assessment, December 2020, pp. 9, 23.

maintain and deliver energy every hour of the year to all locations within the footprint, meeting all demand in each hour reliably at the lowest cost." The MISO RIIA report goes on to state that an energy adequacy assessment "*looks at both system and local level hourly renewable output levels, energy mix, ramping needs and provision, and transmission congestion. As the amount of low cost wind and solar resources increases significantly, RIIA looks at how the location, magnitude, and variability of these resources impact the flexibility requirements, operation of the existing fleet, and utilization of the transmission system*." Energy adequacy therefore ensures there is sufficient resource capability (including capacity but also attributes like flexibility, sustained output, etc.) in all hours of the year to meet demand given more complex factors than just peak demand.[343] The factors considered in energy adequacy assessments could include the potential for widespread generator failures, sustained periods of low wind and solar availability, and the limited energy storage capabilities of batteries and hydropower generators.[344] Because most power systems in the U.S. have long featured at least some hydropower generation with meaningful energy constraints, and some systems are dominated by hydropower, long-term energy adequacy considerations have long been incorporated into resource adequacy planning to a greater or lesser extent.[345]

NERC has proposed to split energy adequacy into **long-term energy adequacy**, covering a timeframe of one or more years, and **operational energy adequacy**, in shorter timeframes (including both shorter-term operations planning and real-time operations).[346] Long-term energy adequacy is concerned with investments in a resource fleet that can meet demand under all kinds of conditions, while operational energy adequacy is concerned with scheduling and dispatching the output of resources as well as their flexibility and other capabilities.

The long development timelines of many electric resources (e.g., generators) means that capacity adequacy and long-term energy adequacy can only be ensured through a years-ahead planning process to invest in capital-intensive supply and demand resources, many of which have decades of useful lives. In many parts of the U.S., this process is centralized with the utility or state regulator. In other places, such as PJM, such planning is conducted largely through capacity

343 The NERC ERATF is currently developing definitions and standards related to energy adequacy. See NERC, Considerations for Performing an Energy Reliability Assessment: ERATF White Paper, March 2023, pp. 1-3.

344 NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December 2020, p. 1.

345 See the 1998 version of PJM Manual 21, Section 3 "Limited Energy Resources." PJM, Manual 21, Rules and Procedures for Determination of Generating Capability, revision 00, effective October 14, 1998.

346 NERC, Ensuring Energy Adequacy with Energy Constrained Resources, December 2020, p. 3.

markets, which rely in part on interactions with market participants based on their future expectations of price signals.

When new resources (generation plants, storage, flexible demand resources) enter service, long-term adequacy improves. When generators retire, long-term adequacy declines. The extent of improvement or decline, and the overall quantity of resources required to meet targets, is measured through well-established and continuously evolving long-term adequacy planning techniques.[347]

As conventional generation is retiring and clean generation is entering service, much of the recent interest in reliability has been focused on long-term adequacy. This interest necessarily turns on the extent to which long-term adequacy techniques are working properly, and/or are driving timely investment decisions and preventing untimely retirement actions.

The rotating outages in Texas during Winter Storm Uri in February of 2021 present a vivid example of insufficient energy adequacy. The extent of the unavailability of generation resources during extreme cold weather coincident with extremely high demand for power for building heat led to the most extensive controlled firm load shed event in U.S. history.[348]

The California rotating outages in summer of 2020 provide an example of a capacity adequacy shortfall. In that event, generators essentially performed as expected during a 1-in-30 extreme heat wave year, and demand simply outstripped available supply.[349]

[347] These techniques were first developed as long ago as the 1940s (see e.g. Giuseppe Calabrese, Generating Reserve Capability Determined by the Probability Method, Transactions of the American Institute of Electrical Engineers, January 1947, Vol. 66, No. 1, pp. 1439-1450) and arguably in the 1930s (see e.g. P.E. Benner, The Use of the Theory of Probability to Determine Spare Capacity, General Electric Review, 1934, Vol. 37, No. 7, pp. 345-348).

[348] FERC, NERC, and Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, November 2021, p. 9.

[349] CAISO also noted two other factors that contributed to rotating outages: (1) Resource planning targets had not adequately ensured sufficient resources to meet demand for both the gross and net load peaks; and (2) existing practices in the day-ahead market at the time exacerbated supply challenges, see CAISO, Root Cause Analysis: Mid-August 2020 Extreme Heat Wave, January 13, 2021, pp. 1-8.

Operational energy adequacy is achieved by balancing supply and demand through careful orchestration of day-to-day operations.[350] Such balancing is a perennial challenge due to the physical need to instantaneously match supply and demand on the electric grid. It is accomplished by securing sufficient flexibility and sustained output capability in the resource fleet so that output can be quickly increased when needed, together with careful optimization of the daily schedules of generators, storage resources, and other resource types.[351]

Because there is still comparatively little storage in the power system, operators must continuously balance supply and demand, using controllable resources to adjust for uncontrolled changes in both demand and supply. Moreover, because power flows over transmission lines according to the laws of physics, the output of controllable resources must be adjusted to indirectly keep transmission flows below limits. These facts give rise to the seminal need for flexibility of controllable (i.e., dispatchable) resources so that operators can match ever-changing demand, while also accommodating changes in supply such as unexpected generation failures, changes in variable resource output, and exchanges with neighboring grids, all the while managing the flows over transmission lines. Since the first multi-generator utility networks were formed in the late 19th century, operators have managed this need through load forecasting, scheduling generator units online and offline, and dispatching flexible resources (including consumption levels of some customers that are willing to be partly curtailed). For many decades, operators have maintained operating reserves to keep up with ongoing changes in supply-demand balance.

It bears emphasis that the variability and uncertainty in supply from variable renewable resources like wind and solar is broadly similar to variability and uncertainty in demand, and is managed using similar (in some cases identical) tools.

When insufficient flexible resources are available, a grid operator cannot maintain proper balance between supply and demand, or cannot properly manage flows over transmission lines, and may need to resort to emergency procedures (including initiating rotating blackouts) in order

[350] NERC defines "long-term planning" as a planning horizon of one year or longer. NERC's remaining time horizons are: operations planning (seasonal through day-ahead), same-day operations, and real-time operations (within the hour). NERC, Time Horizons, May 31, 2023, p. 1.

[351] Balancing is the sole goal of NERC's resource and demand balancing (BAL) series of standards, and is also a key goal of multiple transmission operations (TOP) standards. Nearly all of these standards are targeted at the operations planning, same-day operations, and real-time operations time horizons.

to achieve the needed outcome. On today's interconnected grid, NERC rules for maintaining such balance (in place for many decades) ensure that no grid operator leans too heavily on another without scheduling and paying for such support, and that transmission line flow control is performed properly to avoid cascading failures which could bring down the entire grid.[352]

PJM emergency procedures during Winter Storm Elliott illustrate the potential reliability impacts of insufficient flexibility. PJM's load forecast during the day-ahead scheduling process anticipated elevated load, and scheduled relatively inflexible units (including gas units that needed to schedule gas deliveries on a day-ahead basis) accordingly. However, after this process, the weather became significantly colder than expected, driving demand forecasts higher by approximately ten thousand megawatts, and causing failures of many scheduled generators, requiring new supply to backfill. As PJM called on previously unscheduled generation (including gas generators) to come online and meet the higher demand and backfill failed supply, it emerged that many of the gas units were unavailable because they were unable to procure gas at that late stage (in addition to unavailability due to unexpected equipment failures related to the cold weather). As a result of fuel-related inflexibilities, together with equipment failures, supply was barely able to meet demand, and PJM entered emergency procedures for many hours.[353]

OPERATING RELIABILITY

A power grid is often described as a single, vast, electromechanically-coupled machine.[354] Operating reliability is the robust operation of that machine even in the presence of significant disturbances, corresponding to the first three of NERC's objectives in their Adequate Level of Reliability framework under normal and predefined disturbances.[355] By way of analogy, a legacy grid behaves as if its generators (and customers) were spinning machines physically connected

[352] Because the flexibility needs of an area tend to fluctuate at different times, increasing transmission interconnectivity tends to provide significant flexibility benefits. For NERC standards on balancing requirements, see NERC, BAL-001-2: Real Power Balancing Control Performance, 2013.

[353] PJM, Winter Storm Elliott: Event Analysis and Recommendation Report, July 17, 2023, p. 53. "*As presented in Figure 36, the failure of so many Day-Ahead Market committed units, coupled with the lack of generator parameter updates, led to a high volume of natural gas generators having no Day-Ahead Market commitment and then becoming forced outages due to lack of fuel.*"

[354] To be more precise, any given synchronous interconnection is such a machine. In North America (excluding Alaska), there are four such interconnections: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and the Quebec Interconnection.

[355] Those three objectives are as follows: (1) the system does not experience instability, uncontrolled separation, cascading, or voltage collapse; (2) the system frequency is maintained within defined parameters; and (3) the system voltage is maintained within defined parameters. See NERC, Informal Filling on the Definition of 'Adequate Level of Reliability', May 10, 2023, pp. 1-2.

by rotating shafts. When one generator starts to spin faster, or suddenly trips offline, all of the components of the machine are quickly affected and react in turn, both according to their physics and their electronic control systems. This fact presents challenges:

- The components all must spin at the same, pre-agreed frequency, and coordinate to return to that frequency fairly quickly even if there is an instantaneous change in the system (e.g., due to a component tripping offline).
- The system must be able to tolerate any disturbance without triggering a cascading failure: all the components must react predictably and in a way that is physically compatible with the neighboring components, must remain connected in order to avoid cascading disconnections, and must not act to amplify instabilities; further, at least some components must act to promptly return the machine to a stable, resilient state, i.e., to "damp" the disturbance.

The history of the power grid features periodic instabilities representing failures of operating reliability. For example, the 1965 New York City blackout was triggered by a faulty relay setting at a single hydroelectric generation station in Ontario.[356] This technical fault led to an overload in a connected transmission line, which tripped offline as a protective measure. That line's power flow was forced onto neighboring lines, leading them to overload and trip, and the cascading process thus continued until approximately 30 million people across the Northeastern U.S. and parts of Canada were out of power.[357]

The 1965 blackout illustrates the value of operating with redundant transmission capability, so that the loss of any one facility (for example, the relay, or the first transmission line that tripped) does not cause an overload on any other facility. Known as "N-1 secure" operations, this operating philosophy has been universally adopted as a core principle of power system operations and planning in the decades since, including in NERC standards. Indeed, the 2003 Northeast blackout is often attributed largely to a failure to operate properly in an N-1 secure state, due to a failure of the monitoring system to detect the actual condition of the network.[358]

The method operators use to restore service following such blackouts is called "Black Start", a key part of resilience when stability fails. While Black Start capabilities are almost never used,

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[356] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, p. 104.

[357] This event led to the creation of NERC in 1968, see U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, pp. 10, 104.

[358] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, pp. 17-22.

they are an important and evolving aspect of overall reliability, and NERC invests significant resources in ensuring that all operators have detailed and technically achievable Black Start plans.

NERC has identified several services that are key to maintaining operating reliability in the presence of disturbances, as shown in Figure 32. Several of these are focused on operating reliability, others fall under operational energy adequacy (and are therefore covered above), and one or more arguably fall under both.

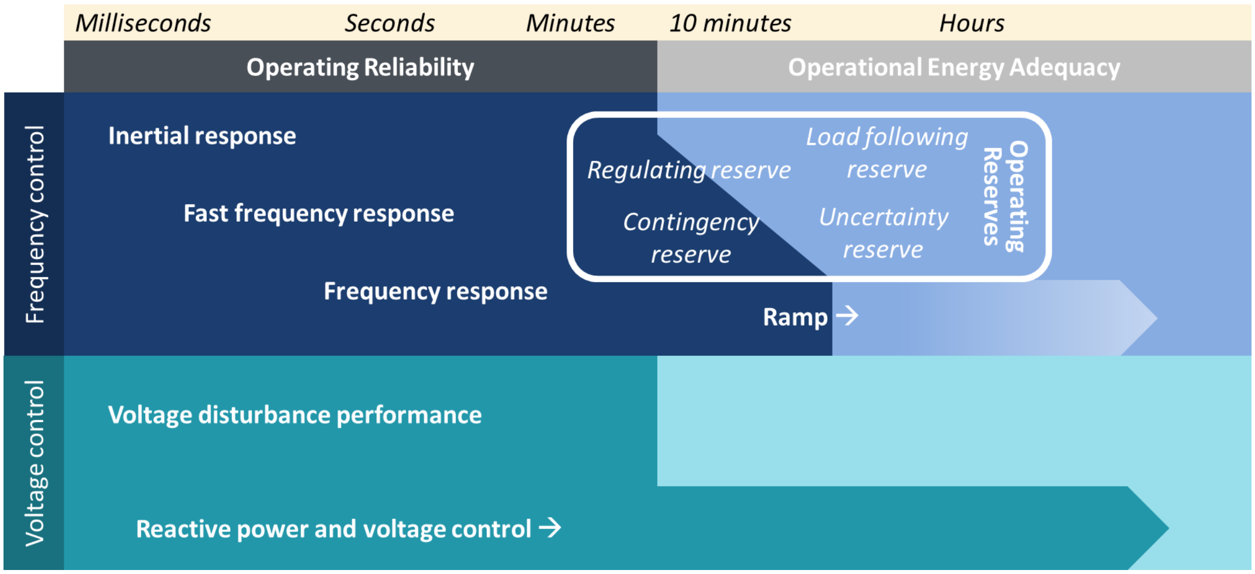
FIGURE 32: NERC ESSENTIAL RELIABILITY SERVICES FALL INTO TWO CATEGORIES: VOLTAGE SUPPORT AND FREQUENCY SUPPORT

	ERSs in Functional Terms	Effects of Lack of ERS Availability
Voltage Support	• The primary objective of Voltage Support is to maintain the voltages in the transmission system within a secure, stable range. • Voltage Support is location-specific and requires reactive power control from reactive resources distributed throughout the power system.	• Localized voltage issues can spread to a wider area, causing loss of load. • Exceeding design voltage parameters can destroy equipment by breaking down insulation. • Undervoltage conditions can lead to motor stalls and equipment overheat. • Voltage collapse can lead to cascading drop in voltage and cause undesirable events.
Frequency Support	• Frequency Support ensures the frequency of the BPS can be synchronized and stabilized for both normal and contingency conditions. • Controlling frequency can be broken into four stages: 1. Inertial Response 2. Primary Frequency Response 3. Secondary Frequency Response 4. Tertiary Frequency Response • Daily operation of the BPS requires a continuous balance of load and resources (generation and demand-side resources). • Operational flexibility is needed to manage real-time changes in load and generation.	• Large frequency deviations can result in equipment damage and power system collapse. • Interconnection frequency deviation can result in: ○ Loss of generation ○ Load shedding ○ Interconnection islanding • Puts BPS stability and the reliability area at risk. • Imbalance in generation and load can overload transmission facilities. • Protection equipment can malfunction or be damaged. • Prolonged imbalance can result in violation of NERC Reliability Standard (BAL-001-1).

Notes and Sources: Some of these Essential Reliability Services can fall under "operational energy adequacy", for example operational flexibility to manage real-time changes in load and generation. See NERC Essential Reliability Services Task Force, A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014, p. 1.

The NERC Essential Reliability Services Task Force produced a whitepaper in 2014 that identified the seven Essential Reliability Services that "*represent a necessary and critical part of the fundamental reliability functions that are vital to ensuring reliability, so these services must be identified, measured, and monitored so that operators and planners are aware of the changing* *characteristics of the grid and can continue its reliable operation*."[359] These are illustrated in Figure 33, together with a depiction of the relevant timescale and the reliability aspect they correspond to. In the case of some of the operating reserves and ramp, there is arguably a continuum between a service's application for operating reliability vs. for operational energy adequacy.

FIGURE 33: DIAGRAM OF ESSENTIAL RELIABILITY SERVICES RELATIVE TO ASPECTS OF RELIABILITY



Notes and Sources: Categories adapted from content in NERC 2014 ERS whitepaper: NERC Essential Reliability Services Task Force, Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014; Electric Power Research Institute, Enhancing Energy System Reliability And Resiliency In A Net-Zero Economy, January 2022.

NERC described the seven Essential Reliability Services in terms of the underlying capabilities that make them possible:

- **Reactive Power Control**. The ability to control a characteristic of the output of any AC electrical device which is called "reactive power." Reactive power is a power systems engineering concept which describes the relationship of the sine wave of AC current to the sine wave of AC voltage. Devices which can control this relationship can control reactive power. Reactive power has the effect of managing the voltage level on the transmission system, thereby facilitating free-flowing transmission of power.

[359] NERC Essential Reliability Services Task Force, A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014, p. iii.

- **Voltage Control**. The ability of the system in aggregate to maintain transmission facility voltages within the nominal ranges required for operating reliability, generally through reactive power but also other means.
- **Voltage Disturbance Performance**. The ability of the system to quickly return to a stable voltage and current profile following a disturbance in order to avoid voltage collapse (i.e., an uncontrolled blackout).
- **Inertial response**. The functional service traditionally provided by generators with spinning mass, which naturally inject power immediately into the grid upon a decline in frequency, thereby arresting and helping to stabilize the decline. Resources without literal physical inertia (such as inverter-based resources) can nonetheless provide inertial response service that provides the identical function.
- **Frequency Disturbance Performance**. The ability of a grid system to restore frequency to appropriate levels following a disturbance (for example, using primary frequency response).
- **Operating Reserves**. Flexible resource capability to quickly increase output (or, in some cases, decrease it) in response to a functional need. There are a variety of operating reserves tailored to different purposes, including contingency reserves (to replace generation that has suddenly failed); load following reserves (to handle expected variation in uncontrolled demand and supply); and regulating reserves (to balance supply and demand in the minute-to-minute timeframe).[360]
- **Active Power Control and Ramp**. This is the ability to balance supply and demand under normal conditions by controlling power output or consumption of flexible resources, either autonomously or through centralized dispatch. Active power control includes non-contingency frequency control and ramping capability.

Essential Reliability Services are provided in various combinations and quantities by generators and other supply resources (such as battery and pumped hydropower storage), by flexible demand-side resources, and by dedicated devices, for example synchronous condensers, STATic synchronous COMpensator (STATCOMs), and even simple capacitor banks. As technologies develop (especially inverter-based technology) and operating practices evolve, the capability of a resource type to provide Essential Reliability Services can increase.

[360] For a description of the different Operating Reserves, see NERC Essential Reliability Services Task Force, A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, October 2014, p. 2.

C. Defining resilience

The term "resilience" can touch on each of the four aspects of reliability described in this report (i.e., capacity adequacy, long-term energy adequacy, operational energy adequacy, and operating reliability). FERC has proposed to define resilience as:

> *"The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."*[361]

Meanwhile, NERC has identified four resilience capabilities:

> *1. "Robustness – the ability to absorb shocks and continue operating*
>
> *2. Resourcefulness - the ability to detect and manage a crisis as it unfolds*
>
> *3. Rapid recovery – the ability to get services back as quickly as possible in a coordinated and controlled manner*
>
> *4. Adaptability – the ability to incorporate lessons learned from past events to improve resilience."*[362]

Robustness, NERC's first resilience capability, features in each of the four reliability aspects:

- In the context of **capacity adequacy** and **long-term energy adequacy**, robustness is necessary to serve load during outlier events that manifest as shocks, such as severe weather. Many such events are included in probabilistic resource adequacy planning models, but there is increasing sensitivity to credible (yet low-probability) event scenarios that do not appear in such models.
- A primary purpose of **operational energy adequacy** is to manage uncertainty in real-time operating outcomes relative to forward scheduling expectations. For example, securing flexibility capability to handle a large and sustained deficit of wind generation relative to the day-ahead scheduling plan.

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[361] Grid Resilience in Regional Transmission Organizations and Independent System Operators, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, FERC, 162 FERC ¶ 61, 012, Order Terminating Rulemaking Proceeding, Initiative New Proceeding, and Establishing Additional Procedures, January 8, 2018, p. 12.

[362] NERC, Reliability Issues Steering Committee Report on Resilience, November 8, 2018, p. 2.

- Robustness is the definition of **operating reliability**, which is focused on the ability to withstand major disturbances and quickly return to a stable condition. A prominent example of operating reliability is meeting demand immediately after the sudden and unexpected failure of a large generator, a prototypical example of robustness.

D. Measuring and managing reliability

Planners measure electric grid reliability across the three domains using well developed tools, as detailed below. Table 4 below provides a summary for each reliability domain of the objective, its measurement, and management methods.

TABLE 4: GRID OPERATORS USE WELL-ESTABLISHED METHODS TO MEASURE AND MANAGE RELIABILITY ACROSS ITS VARIOUS ASPECTS

	Measurement Methods	Metrics Including Standards/Targets	Management Methods
Capacity Adequacy and Long-Term Energy Adequacy	Long-range forecasting & probabilistic modeling of supply & demand patterns given weather	Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE), etc. *Standard target*: LOLE of 1 event in 10 years	Utility and ISO/RTO resource planning & investment (incl. capacity markets & other price mechanisms) under state (& federal) regulatory oversight
Operational Energy Adequacy	Metering to calculate real-time power balance Assessment of physical capabilities of resource fleet	Real-time Area Control Error (ACE) calculation. *Required limit*: see NERC Standard BAL-001[363] Ramp-limited “headroom” & “footroom” MW capability of resource fleet at various timescales	Operational forecasting, optimization of resource schedules, ongoing procurement of various flexibility/ramp reserves, & regional coordination (incl. markets)
Operating Reliability	Detailed sub-second simulations of the physics of the actual power system	System strength, often quantified as Short Circuit Ratio (SCR) Steady state voltage standards are specified by NERC TOPs,[364] while acceptable control of frequency excursions beyond 36 MHz is set by NERC in BAL-003[365]	Grid codes for inverters Operational screening and constraints Long-term transmission planning and investment in stabilizing devices

[363] NERC, BAL-001-2: Real Power Balancing Control Performance, April 16, 2015.

[364] CAISO RC West, System Operating Limits Methodology for the Operations Horizon, Rev. 2.0, October 1, 2022, p. 18.

[365] Except single Balancing Authority Interconnections (e.g., the Texas Interconnection). See NERC, BAL-003-2: Frequency Response and Frequency Bias Setting, November 5, 2019 (with errata published July 15, 2020), p. 2.

MEASURING AND MANAGING CAPACITY ADEQUACY AND LONG-TERM ENERGY ADEQUACY

Resource adequacy holds when the installed fleet of resources has sufficient total capacity and flexibility capabilities to ensure that supply nearly always exceeds demand, and there are therefore a minimal number of emergency shortfalls and nearly zero "loss of load" events such as rolling brownouts or blackouts. Resource adequacy planners use probabilistic reliability models, or "Loss of Load Expectation" (LOLE) models, to measure the resource adequacy reliability of a system.[366] LOLE models are probabilistic simulations of a given resource mix that assess the likelihood that demand will exceed supply. Such models evaluate thousands of scenarios, reflecting probability distributions of weather for the geography (and corresponding patterns of demand, wind and solar output, and hydropower generation) as well as historical patterns of generator outages. These simulations produce a reliability metric (such as LOLE), and ultimately are calibrated to identify the quantity of supply resources needed to meet a target reliability metric.[367]

The most commonly used reliability metric produced by LOLE models is the eponymous "LOLE", which is generally the number of events per period (often a decade) in which demand is expected to exceed supply in the model.[368] For example, when a system exhibits an LOLE of 1-in-10 (a common target), it is expected to have a single shortfall event across all the various weather patterns and generator outage patterns that are anticipated to occur over a future 10--year period.

Both LOLE models and the LOLE metric can apply to traditional capacity adequacy planning (in which case model methods and inputs are tailored to focus on periods of peak demand) or to energy adequacy planning (by evaluating all hours of the year and taking into account limits on resource capability other than maximum output capability, for example weather sensitivity and limited energy output capability.

[366] Johannes Pfeifenberger, et al., Resource Adequacy Requirements: Reliability and Economic Implications, September 2013.

[367] While events in which demand exceeds supply are called "loss of load" events, in actual operations, demand can often exceed supply without the need to initiate rotating outages by instead relying on emergency imports, emergency capacity of generators, voltage reduction, and other emergency actions.

[368] For further on resource adequacy metrics, see EPRI, Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics, April 25, 2022.

Metrics similar to LOLE that capture the extent to which simulated demand is expected to exceed supply include Loss of Load Hours (LOLH), the average number of hours in a year meeting that condition, and Expected Unserved Energy (EUE), the average annual consumer demand that exceeds supply (in terms of total energy). An alternate interpretation of 1-in-10 LOLE is one full service day of interruption per decade, i.e. an LOLH of 24 hours per decade or 2.4 hours per year.[369] The term "Loss of Load Probability" (LOLP) refers to the likelihood of a loss of load event in a given interval, ranging from an hour to a decade. The 1-in-10 standard amounts to an annual LOLP of 0.1.

TABLE 5: COMPARISON OF RESOURCE ADEQUACY METRICS

Metric	Description	Pros	Cons	Examples
Loss-of-Load Probability (LOLP)	Probability of demand exceeding available resources at least once within a year. **Units: % chance of >= 1 event per year**	Easy to calculate and understand	Does not consider duration or size of an unserved load event	**Northwest Power and Conservation Council**: 5% LOLP
Loss-of-Load Events (LOLE)	Expected number of events per year in which demand is not served. One event in ten years translates to 0.1 LOLE per year. **Units: Events per year**	Easy to calculate and understand *Used by most U.S. systems*	Does not consider duration or size of an unserved load event	**Most U.S. Systems**: 1 loss-of-load event per decade or 0.1 event per year
Loss-of-Load Hours (LOLH)	Expected number of hours per year in which demand is not served. One day in ten years translates to 2.4 LOLH per year. **Units: Hours per year**	Considers the loss of load duration *Used by NERC*	Does not consider size of an unserved load event	**SPP**: 2.4 LOLH per year (equal to 1 day in 10 years)
Normalized Expected Unserved Energy (EUE)	Expected MWh of load that will not be served as a result of demand exceeding available supply. Can be normalized as % of load. **Units: % of expected annual load**	Considers both the duration and depth of supply shortages *Used by NERC*	Requires more sophisticated statistical methodologies	**Alberta**: Max annual EUE of 800 MWh **Australia NEM**: Max of 0.002% normalized EUE

Notes and Sources: Sam Newell, et al., Alternative RA Metrics, and RA Construct Elements, June 10, 2020, p. 3.

The final output of the resource adequacy planning process (especially for traditional capacity adequacy planning) is often a simple metric called the "planning reserve margin" or PRM. The reserve margin is the ratio of the aggregate rated power (i.e., capacity) of all resources on a system to the typical annual or seasonal peak demand on that system, and the planning reserve margin is the approximate reserve margin that yields the target reliability metric (LOLE or otherwise) in the LOLE model. The PRM only approximately yields the target reliability level because different resources with the same rated capacity provide varying levels of LOLE improvement. For example, compared with a perfect generator that never fails, an otherwise identical generator with a high probability of failure contributes less to meeting the capacity adequacy requirements of the system. Different metrics for installed resource requirement are

[369] Samuel Newell, et al, Alternative RA Metrics and RA Construct Elements, the Brattle Group, presented to the MISO Resource Adequacy Subcommittee, June 10, 2020.

sometimes used to avoid this issue.[370] As factors other than the aggregate rated power capacity of resources on the system take a greater role in adequacy (i.e., as energy adequacy becomes more important), the PRM becomes less relevant.

The same planning models can be used to calculate a uniform resource adequacy value of different resources, denominated in units of perfect capacity. The model measures the improvement in reliability metric when adding a resource with a particular output pattern (for example solar or storage), then re-runs the model to find the amount of always-available "perfect capacity" that yields that same outcome. The resulting capacity value of any resource type can thereby be measured uniformly by the quantity of equivalent resource adequacy improvement of a perfect resource. This method, pioneered in the 1960s, is often called "Effective Load Carrying Capability" or ELCC.[371]

As energy becomes abundant during peak hours and risk therefore shifts to other hours, grid operators are adding new metrics to complement or replace PRM for expressing the size of the resource fleet required to meet long-term adequacy requirements. In particular, ISOs/RTOs are beginning to state the quantity of perfect supply needed to meet the target reliability metric. In this context, "perfect supply" is a theoretical concept referring to supply that is available 24x7—the unit of measure used by ELCC. The target reliability metric could be an LOLE of 1-in-10, or a normalized EUE value that provides comparable reliability to customers. A related concept is "marginal reliability impact", which expresses the marginal change in reliability metric with an incremental change in supply or demand.

Various processes are in place in every part of North America to ensure resource adequacy targets are met, as follows:

- **Utilities that are not members of ISOs/RTOs** conduct periodic resource adequacy assessments, participate in NERC national assessments, and conduct resource planning processes under state regulatory oversight in order to add resources when necessary to meet targets in light of planned retirements and growth in demand.
- **Utilities in ISOs/RTOs with a minimum PRM requirement** must demonstrate a portfolio of resources with a total capacity value that meets the PRM requirement set by the ISO/RTO, or face a penalty. This approach is generally deployed in traditionally regulated states, and so

[370] For example, the Forecast Pool Requirement in PJM, which is measured in terms of a uniform derated capacity value used across all resources. See PJM, 2022 PJM Reserve Requirement Study, October 4, 2022, pp. 41-43.

[371] L. L. Garver, Effective Load Carrying Capability of Generating Units, IEEE Transactions on Power Apparatus and Systems, Aug. 1966, vol. PAS-85, no. 8, pp. 910-919.

the requirements are met through state-regulated IRPs, whether through self-build (much of the SPP ISO/RTO) or competitive solicitation (the CAISO ISO/RTO).

- **Utilities in ISOs/RTOs with a capacity market** must purchase capacity from the central market in the amount specified by the ISO/RTO. The ISO/RTO in turn procures capacity from resources through the market for a month (NYISO) or a year (PJM, MISO, ISO New England). Some utilities in capacity markets are traditionally regulated and own capacity resources roughly commensurate with their purchase obligation, managed through IRPs; others are restructured such that the wires utility is not involved in generation, and supply is provided by competitive third parties.
- **Alberta and Texas** feature energy-only markets in which resource adequacy reliability levels are nominally a market outcome rather than an exogenous target. However, resource adequacy studies are periodically performed in those markets, and market designs occasionally re-calibrated to boost reliability.

The mechanisms above each act to ensure resource adequacy: IRPs drive new resource investment when anticipated reserve margins would fall below the PRM target; capacity markets are designed to increase prices as reserve margins decline through retirements or load growth, and vice versa; ISOs/RTOs adjust required PRMs or capacity purchase requirements as necessary to ensure reliability; and state regulators (overseeing IRPs) as well as the Federal Energy Regulatory Commission (FERC, overseeing the ISOs/RTOs) aim to ensure the processes are working properly. NERC coordinates and reports on the processes and their outcomes across all planning regimes.

MEASURING AND MANAGING OPERATIONAL ENERGY ADEQUACY

A system has adequate flexibility to meet reliability needs when the operator can match supply to demand on a minute-to-minute and hour-to-hour basis without inappropriately leaning on neighbors through unscheduled flows, notwithstanding challenging internal conditions such as rapid and sustained increases or decreases in demand or supply (either expected or unexpected) or sudden loss of supply. System flexibility is provided by controllable resources that can rapidly change their output up and down, including by turning on or off gas combustion turbines, deploying flexible demand response like water heaters, dispatching batteries or hydropower, or simply changing the output levels across many online generators. A system with lots of flexible resources, a highly optimized deployment system, and/or moderate ramping needs will balance well, and one without those things will not.

The relative balancing performance of a system is measured through the metric called "Area Control Error" or ACE, first documented in 1950 by Nathan Cohn.[372] ACE compares the amount of net energy flowing in or out of an area (a "Balancing Authority Area" or BAA, such as an ISO/RTO or non-ISO/RTO utility) with the net schedule for such flows arranged with neighbors, plus a term related to system frequency.[373]

To illustrate how the ACE metric works, first note that, if a system is exactly meeting its internal customer demand with its internal generation, there will be no net exchanges with neighbors. Therefore, net exchanges are a measure of the extent to which a system is producing more or less than its internal demand. In general, such exchanges are mainly the intentional, scheduled result of regional trade, and are therefore considered part of being in balance. However, some amount of such exchange is the unintentional side effect of imbalance. The first term in the ACE equation thus compares actual net exchange with scheduled net exchange and takes the difference as error.

The frequency term introduces the shared need to control frequency across the entire interconnection (e.g., the Western Interconnection). When frequency is too low, all BAs must aim to export more power than scheduled, i.e. through targeting increased generation output above the amount needed for internal demand net of scheduled interchange. This increased output results in excess system energy, which is naturally stored in increased rotational inertia of generators and other spinning masses on the system (i.e., frequency increases, thus restoring target frequency).

For generation dispatchers at Balancing Authorities, ACE is a key performance metric that is under constant monitoring, and NERC standards place strict limits on ACE excursions.

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372 Resource adequacy shortfalls also ultimately manifest as temporary ACE problems, but these are rectified through service interruptions, which then restore ACE; for first documentation of ACE, see Nathan Cohn, Control Of Power Flow On Interconnected Systems, Proceedings of the American Power Conference, 1950, vol. 12, pp. 159-175.

373 There are other miscellaneous terms that can be ignored for our purposes, such as cumulative clock error correction for vintage clocks that tell time based on the AC frequency of the grid.

ACE is calculated as follows (see NERC, Balancing and Frequency Control, January 26, 2011, p. 15.)

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

Where:
NI_A = Actual Net Interchange
NI_S = Scheduled Net Interchange
B = Frequency Bias Setting
FA = Actual Frequency
FS = Scheduled Frequency (i.e., 60 hertz)
IME = Interchange Meter Error

Many flexibility tools have been used for decades to manage ACE, for example:

- Procurement and ongoing deployment of frequency regulation reserves, for direct second-to-second and minute-to-minute control of ACE through centralized dispatch
- Procurement and occasional deployment of various intrahour contingency reserves or other ancillary services to restore ACE following sudden loss of supply or other contingency
- Intrahour dispatch, whether through real-time energy markets (in ISOs/RTOs) or other dispatch methods (outside ISOs/RTOs)
- Hourly, intraday, day-ahead, and longer-lead scheduling of turn on/turn off schedules for resources, including forecasting techniques and procurement of various reserves products such as flexible ramping products in CAISO.

Effective utilization of existing flexibility includes system dispatch that accounts for expected short-term ramping needs. Currently, most ISOs/RTOs feature single-period dispatch, where resources are dispatched in real-time based on projected needs in the single upcoming dispatch period. This contrasts with the multi-interval dispatch approach currently utilized by CAISO and NYISO, in which resource dispatch is optimized over a longer time period lasting approximately one hour.[374] This greater look-ahead period provides insight into future grid conditions and allows operators to schedule resources where they provide maximum real-time value, thereby avoiding short-sighted dispatch of resources when they might better serve future flexibility needs. Greater flexibility needs increase the importance of a greater look-ahead period in dispatch.

Ancillary services are mainly targeted at managing and deploying flexibility in real-time operations. To the extent that system needs cannot be fulfilled by existing ancillary services, they can be addressed through expanded reserve deployment or met with new "fit-for-purpose" ancillary service products. As an example of the former, ERCOT increased its level of operating reserves following the devastating blackouts caused by Winter Storm Uri.[375] As an example of the latter, several ISOs/RTOs have introduced up and down ramp products to meet net load changes that are unexpected (and in some cases expected), including CAISO, MISO, and SPP.[376] CAISO has

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[374] In the five-minute real-time market, CAISO uses multi-interval optimization to provide dispatch instructions for 65 minute intervals, whereas in the fifteen-minute real time market, CAISO optimizes over a time period up to two hours in the future. See CAISO, Special Report on Battery Storage, July 7, 2023, p. 5; NYISO, Manual 12: Transmission and Dispatch Operations Manual, November 2023, pp. 112-113.

[375] Potomac Economics, 2022 State of the Market Report for the ERCOT Electricity Markets, May 2023, pp. 86-87.

[376] Kathleen Spees and Samuel Newell, Efficiently Managing Net Load Variability in High-Renewable Systems: Designing Ramping Products to Attract and Leverage Flexible Resources, February 2022, p. 11; CAISO, "Flexible

further proposed a day-ahead Imbalance Reserve product designed to account for differences between day-ahead forecasted net load and real-time net load.[377] In general, ISO/RTO markets are open to all resource types that are technically capable of providing a service, such that battery storage and demand response that can quickly provide a sustained response to dispatch signals (not to mention gas combustion turbines, hydropower ,and other conventional generators) can sell new reserve products like this.

MEASURING AND MANAGING OPERATING RELIABILITY

Because alternating current technology involves electromechanically coupling a great many devices across a vast interconnection, it has always suffered from inherent stability vulnerabilities of various kinds that must be guarded against. A system is reliably stable when it can withstand brief but potentially intense disturbances (such as a short circuit, transmission line trip, etc.) without undergoing cascading failures, instead returning to a stable and resilient state. Stability (i.e., operating reliability) is ultimately assessed through sophisticated sub-second time-evolution simulations of the physics of the electric grid and all its components (generators, power lines, substations, customer devices).

Well-tuned devices (conventional generators and sophisticated inverter-based machines such as solar, storage, wind, and high-voltage DC converters) are extensively engineered to contribute to stability, remaining connected and actively damping excursions in key parameters (such as voltage and frequency) during and after severe disturbances. However, to the extent that legacy inverter-based generators, such as older or poorly configured solar and wind farms, displace well-tuned devices, especially those with very high “fault current”, “weak grid” conditions can emerge, threatening operating reliability. A simplified metric to measure weak grids is called the “Short Circuit Ratio” or SCR. It is defined as the ratio of the nameplate power rating of an inverter-based resource to the “short circuit current” at the point of connection of that same resource to the grid.[378] Short circuit current is the current that simulations show flows through the applicable point when it is shorted to ground (i.e., put into a short circuit condition). SCR is based on the premise (correct in a world dominated by legacy inverters, and especially without the grid-forming inverters described below) that synchronous machines are the only source of strong and

ramping product”, 2023, accessed December 13, 2023; MISO, Business Practice Manual 002, September, 30, 2022, pp. 52-54; FERC, 172 FERC ¶ 61,027, July 16, 2020, Order Accepting Tariff Revisions.

[377] CAISO, Revised Final Proposal – Day-Ahead Market Enhancements, May 1, 2023, p. 5.

[378] See National Grid ESO, Provision of Short Circuit Level Data: A System Operability Framework Document, February 2022, pp. 4-5.

stable voltage support, and that short circuit current is a good proxy for electricity proximity to such synchronous machines.

When the magnitude of the short-circuit current is comparable to nameplate rating of the inverter (e.g., when the SCR is below 2), operators look to solutions to increase system strength (such as installing nearby grid-forming inverters or synchronous condensers, essentially a very large motor that serves to provide a high-quality AC voltage source for brief periods of time).

Stability is highly specific to circumstances. Therefore, while SCR is a valuable screening metric, it cannot approach the value of performing detailed simulations for a full measure of stability. If such simulations survive perturbations and quickly return to normal conditions, they are considered stable. Otherwise, they are not. Among the most important circumstances is the quality of the inverter itself—inverters with technology approaching so-called "grid-forming" methods can contribute to stable operations in a similar way to conventional spinning machines (albeit with a lesser magnitude of fault current, which may require other system adjustments to adapt).

GRID FORMING INVERTERS

President Robb concisely describes a helpful vision for addressing concerns with the changing technologies for resources that provide Essential Reliability Services:

> *"A future grid with grid forming inverter technology, coupled with battery energy storage systems, will be uniquely capable to support stability and frequency needs. The pace of change toward an inverter-based system is outpacing our ability to adequately study that future system with enough depth and breadth. Experience around the world shows that some amount of grid forming inverters will be needed throughout the system to ensure adequate grid-stabilizing attributes are available. Enabling grid forming IBRs in all future battery energy storage system projects would provide a dispatchable source of frequency at a relatively low-cost solution that helps ensure system-wide stability. The benefits are difficult to quantify today due to study limitations, but it is clear that as synchronous machines retire, their essential reliability services, such as the provision of frequency, must be replaced to ensure the reliable operation of the system of the future. NERC recommends that industry proactively plan to ensure sufficient grid forming*

> *inverters are installed on the system under future operating conditions in its recently published paper on this topic."*[379]

However, a growing handful of projects around the world are demonstrating that so-called "grid-forming inverter" technology is capable of contributing to dynamic voltage stability. According to a recent NERC report, "*GFM [grid-forming] technology is commercially available and field-proven for transmission-connected applications, particularly for BESS [battery energy storage systems]*" and "*GFM technology has been shown to operate reliably and provide stabilizing characteristics in transmission systems outside of the BPS [Bulk Power System, i.e. the U.S. transmission system] in areas of high IBR [Inverter-Based Resource] penetrations and areas of low system strength. GFM BESS presents a unique opportunity to support system stability (e.g., transient, oscillatory, voltage) with a relatively low incremental cost to all resources and end-use consumers.*"[380] The NERC report elaborates urgent next steps to best take advantage of this new capability as the sector continues to rapidly deploy utility-scale batteries.[381] While those steps are being pursued, dynamic voltage stability can be secured through two supplementary steps: (1) non-GFM inverters can be programmed with the latest grid-support controls, such as those specified in IEEE 2800;[382] (2) in areas of the grid that still require additional dynamic voltage stability, synchronous condensers can be installed, or condensing-mode capability can be retrofitted to existing conventional generators to allow them to provide stability without burning fuel.

E. Changing needs and strengths of reliability in an evolving grid

In comments at the 2023 Senate hearing on electric grid reliability, NERC President Robb highlighted emerging reliability challenges due to a changing resource mix, inadequate

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[379] NERC, Statement of NERC CEO James Robb at 2023 FERC Technical Conference on Reliability, November 9, 2023, p. 8.

[380] NERC, White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems, September 2023, p. vi.

[381] NERC, White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems, September 2023, pp. v-40.

[382] IEEE, IEEE 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems, April 22, 2022.

performance standards for new resource types, a changing climate, and increasing electricity demand. [383]

He further identified the path forward:

> *"There are three key reliability priorities, outside of cyber/physical security, that will help us address these challenges and be successful. First, we must manage the pace of the transformation in an orderly way, which is currently not happening. Second, we must identify and integrate new resources to replace retiring generation that provides both sufficient energy and essential reliability services needed for stable grid operations. Finally, due to the changing fuel mix, the dynamics associated with DERs [distributed energy resources, such as rooftop solar], and the potential for demand side management to support reliability, we must shift the planning focus. Whereas resource planning traditionally focused on having enough generation capacity during peak demand conditions ("capacity on peak"), the focus must be broadened to include the need for sufficient energy at all times ("energy 24x7")."*[384]

In Table 6, we summarize the challenges and solutions for integration of renewables into the grid, including the shift in planning focus described by President Robb.

[383] U.S. Senate Committee on Energy and Natural Resources, "Full Committee Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts," June 1, 2023, accessed December 15, 2023; James B. Robb, Testimony of James B. Robb, U.S. Senate Committee on Energy and Natural Resources, June 1, 2023.

[384] James B. Robb, Testimony of James B. Robb, U.S. Senate Committee on Energy and Natural Resources, June 1, 2023, pp. 3-4.

TABLE 6: EXISTING TOOLS WILL SHIFT IN IMPORTANCE, EVOLVE, AND ITERATE TO MATCH EVOLVING SYSTEM NEEDS AND STRENGTHS

	Shifting Challenges	Shifting Solutions
Capacity adequacy and Long-Term Energy Adequacy	• More variability in potential scarcity conditions • Increased demand for electricity with electrification of other sectors	• Shift to EUE metrics and away from reserve margin metric • Improve precision of probabilistic reliability models, incorporate longer weather histories, consider the effect of climate change over the course of such weather histories • Potential to incorporate non-probabilistic scenario-based planning for resilience
Operational Energy Adequacy	• More variability and uncertainty • Potential to unlock considerable new sources of customer-side flexibility	• Greater importance on operational scheduling and dispatch tools, including forecasting • New ancillary services for ramp and other flexibility services to operate and retain or attract flexible resources • Improved pricing of flexibility services in ISOs/RTOs
Operating Reliability	• Faster dynamics • More responsive resources • More computer-mediated transient responses • Greater steady-state voltage regulation capability	• Greater role for stability • Require and configure grid-forming inverters • More synchronous condensers • More HVDC for long-haul access to remote, low-cost resources, and for stability improvement